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Evaluation of Natural- and Forced-Draft Staging Air Systems for Nitric Oxide Reduction in Refinery Process Heaters
Volume 1. Technical Report

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EVALUATION OF NATURAL- AND FORCED-DRAFT STAGING AIR SYSTEMS FOR NITRIC OXIDE REDUCTION IN REFINERY PROCESS HEATERS

Volume I. Technical Report

by

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ABSTRACT

Results of pilot-scale tests to evaluate combustion modifications for emission reduction and efficiency enhancement on petroleum process heaters are reported. The objectives were to determine NO_x emission reductions, thermal efficiency changes, long-term performance, and cost of both natural draft and forced draft staged combustion air modifications. Forced draft staged combustion air modifications had been shown to be the most promising combustion modification in previous pilot-scale tests. The test unit was a vertical cylindrical natural draft crude heater and the test fuels were natural gas, refinery gas, and a combination of No. 6 oil and refinery gas. The unit had a 16 MW heat input capacity and was capable of a maximum throughput of 108 m^3/h of crude oil (rated input 96 m^3/h).

A natural draft staging air system, capable of providing 50 percent of the staging air for 100 percent refinery gas firing and crude charge rates of 55 to 90 percent rated capacity, reduced NO emissions by approximately 50 percent. The stack O_2 was lowered from 4 percent baseline to 2 percent low NO condition. The efficiency gain with the natural draft staging air system was approximately 1.5 percent. Natural draft staged combustion air (4 percent stack O_2) with 80 percent oil/20 percent gas firing provided NO reduction of 30 percent and an average efficiency gain of 0.6 percent. Lowered excess air with staging (4 percent $O_2 \rightarrow 2$ percent O_2) for the 80/20 mix provided an NO reduction of approximately 60 percent and an average efficiency gain of 3.6 percent but unacceptable CO emissions and smoking problems. While firing 80 percent oil 20 percent gas, the forced draft staging air system provided approximately 40 percent of the total combustion air and an NO reduction of 40 percent (6 percent baseline stack O_2 to 3 percent low NO stack O_2). The efficiency gain with the forced draft staging air system was 5 percent. A 15-day evaluation of the natural draft staged air system revealed no special operating difficulties or process constraints. Costs of the natural draft and forced draft staged air system are compared. The natural draft system (staging with lowered excess air) has a cost of $0.03/lb NO on a 29.3 MW natural draft process heater compared to a cost of $0.32/lb NO for a forced draft system.

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Limitations on Application of Data Reported

The pollutant emission data cited in this report pertain to one specific classification of refinery process heaters, i.e., vertical cylindrical natural draft crude heaters. These data should not be used to estimate mean emissions from other types of heaters or to predict emission reduction potentials of combustion modifications until the modifications have actually been carried out on the different heater types.

SECTION 1.0

INTRODUCTION AND SUMMARY

1.1 OBJECTIVES AND SCOPE

The objective of this program was to investigate advanced combustion modification concepts requiring relatively minor hardware modifications that could be used by operators and/or manufacturers of selected industrial process equipment to reduce emissions and to improve thermal efficiency. The investigation was to be performed for equipment in which the modifications would be most widely applicable and of the most significance in mitigating the impact of stationary source emissions on the environment. Another objective was to assess the feasibility of these modifications to the extent that they could be readily adopted by the fuel burning equipment manufacturers. The path to this goal included concept definitions, economic and technical assessment, subscale performance evaluation tests, cost/benefit analysis, pilot-scale equipment modification or retrofit, pilot-scale performance evaluation tests, and preparation of final reports and instructional guidelines.

Of the advanced combustion modification concepts considered for this study, staged air lances was considered a feasible approach to significant NO_x reduction. The follow-on study to the work conducted under EPA Contract No. 68-02-2645 (Ref. 1) had two specific objectives with respect to staged air lances. The first objective was to evaluate the potential of natural draft staged air lances for reducing NO_x emissions and increasing thermal efficiency. A second objective was to evaluate the performance of a staged air system on a heater firing 100 percent residual oil.

1.2 REVIEW OF PREVIOUS WORK WITH STAGED COMBUSTION AIR LANCES ON A FULL-SCALE OPERATING PROCESS HEATER

Previous work has been done on the effects of forced draft staged combustion air lances on a pilot-scale natural draft process heater (Ref. 1). The forced draft system mechanically pushed the staged combustion air through a series of lances into the furnace. A fan supplied approximately fifty percent of the total combustion air to the lances through a manifold and flexible tubing. All of the combustion air in an unmodified natural draft heater is naturally pulled through the primary and secondary air registers by the partial vacuum in the furnace caused by the tendency of hot gases to rise up the stack.

The initial test series was conducted to determine heater performance over a range of operating variables such as excess air, load, and air register settings for gas and/or oil firing. For both gaseous fuel and gas/oil firing NO_x emission reductions were reported relative to a 4 percent stack O_2 baseline condition. NO_x reduction obtained by lowering the excess air without staged combustion (4 percent to 2 percent O_2) was 15 percent below baseline firing refinery gas and 35 percent below baseline firing a 50-50 mixture (by heat input) of refinery gas and No. 6 oil (4 percent to 2 percent O_2). Accompanying reductions in fuel consumption were 2.8 percent firing refinery gas and 3.0 percent firing both fuels. Once the performance of the heater was documented over its normal range of operating parameters, staged combustion air was implemented. A prototype system, constructed largely of polyvinyl chloride pipe, fittings, and valves with 24 stainless steel lances (four per burner) was built. The heater was then reevaluated over the same ranges of operating parameters. During testing of the staged air system burner stoichiometric ratios, staged air insertion height and staged air lance orientation were varied. The burner equivalence ratio is defined as the air-to-fuel ratio at the burner relative to the stoichiometric air/fuel ratio. An optimum low-NO_x operating condition was defined as the configuration at which the lowest NO_x concentrations were obtained while still permitting stable heater operation without a significant increase in CO emissions. This condition was defined for gaseous fuel and for a 50/50 mixture of No. 6 oil and gas.

A 30-day test was conducted with the staged air system in continuous operation firing scrubbed refinery gas (absorber gas) at the optimum low-NO_x condition. Baseline oxygen was decreased from 4 percent to 2 percent. The combination of staged combustion air and lowered excess air reduced NO_x

emissions by 71 percent below a baseline of 66 ng/J (as determined by spot measurements prior to and at the completion of the 30-day test) while decreasing fuel consumption by nearly 5 percent. Without an automatic O_2 trim system, the staged air system operating at 4 percent stack oxygen reduced NO_x emissions by 60 percent below the 66 ng/J value. Fuel consumption decreased by about 0.2 percent. The staged combustion air system functioned effectively and continuously with little operator attention and little lance deterioration over the 30-day period.

Cost data were calculated in terms of dollars per megagram of NO_x reduction for forced draft staged combustion air with and without lowered excess air. The cost of staged combustion air on a natural draft process heater applied at normal stack oxygen was calculated as \$2636/Mg NO_x for a 16.1 MW heater and decreased to \$1934/Mg at 147 MW heat input. The cost of forced draft staged combustion air combined with lowered excess air on a natural draft process heater applied at 2 percent stack O_2 was calculated as \$1089/Mg for a 16.1 MW unit. The cost became negative for a 147 MW unit indicating a savings associated with the combined modifications. These costs included the purchase of an automatic stack draft controller to allow operation of the heater at lowered O_2.

Recommendations for further test work were made involving combustion modifications for NO_x control on process heaters. The recommendations included evaluation and testing of a naturally drafted staged air system and testing of staged air systems with 100 percent oil firing. These recommendations were incorporated into the present test program described in the following section.

1.3 PRESENT TEST PROGRAM APPROACH

The crude heater tested is the same one described in EPA Contract No. 68-02-2645 (Ref. 1). The heater is a natural draft vertical cylindrical crude heater containing six burners, capable of combined fuel firing. The staged air system has 24 ports (four per burner) through which either natural draft or forced draft staged air may pass.

Prior to staging tests, two days of baseline data with 100 percent gas firing were collected. The initial tests with natural draft staged air and 100 percent gas firing were intended to determine the best NO_x reduction using various lance injection areas. The best low-NO_x operating condition was defined as the configuration at which the lowest NO_x concentrations were obtained while still permitting stable heater operation without a significant increase in CO emissions. Once the optimum lance injection area was determined, this injection area was kept constant as load and stack O_2 and burner equivalence ratios were varied.

For the second phase of the test program, the prototype forced draft staged air system was rebuilt. The system was constructed largely of polyvinyl chloride pipe, fittings, and valves with 24 stainless steel lances (four per burner). The crude heater was then evaluated with forced draft staged air and 80/20 oil/gas mixture over a number of operating parameters including burner equivalence ratio, staged air insertion height, and staged air lance orientation. The heater could not be run on 100 percent oil as originally hoped. The original plan was to have a temperature controlled valve in the oil line such that the oil and gas flow rates would be automatically adjusted to satisfy the thermal input requirements. Since the valve was never installed, the crude oil outlet temperature was automatically controlled by gas flow and manually controlled by oil flow. For safety and control purposes, the plant could not run the heater solely on manual control. Some testing with natural draft staged combustion air using the optimum injection area determined in Phase I was also conducted with the 80/20 oil/gas mixture.

A 15-day test was conducted following Phase II completion with the natural draft staged air system in continuous operation firing refinery gas at the optimum low-NO_x condition. System performance and durability were evaluated as well as the ability to maintain steady heater operation at the low-NO_x condition.

The cost effectiveness ratio, based on the permanent natural draft staged air system design, was evaluated and compared to a forced draft staged air combustion system.

A summary of the significant results obtained during the pilot-scale test program is given in Table 1-1. It should be noted that the NO_x was measured on a dry basis, thus all emissions data, reductions, and cost data are reported as NO. Previous work on the same refinery heater with 100% gas firing and 50% oil/50% gas firing indicated that NO_x measured on both a dry and wet basis was the same (i.e., no NO_2 detected). NO emissions were measured on a dry basis and the mass emission rates reported herein are calculated on the molecular weight of NO_2 (see Section 5.1 for mass emission calculation).

1.4 CONCLUSIONS

The following conclusions are drawn from the field testing and analyses performed on data collected during these tests.

- The objectives of the program were satisfied regarding the evaluation of potential for natural draft staged combustion air and the application of staged air systems for heaters burning 80 percent oil/20 percent gas.
- Natural draft staged combustion air lowered NO emissions by approximately 45 percent (4.0 percent O_2 → 3.9 percent O_2) while low excess air decreased NO emissions by 20 percent with 100 percent gas firing (4.0 percent O_2 → 2.0 percent O_2).
- In a short-term test, the combination of natural draft staged combustion and lowered excess air reduced NO emissions by approximately 50 percent while decreasing gas consumption approximately 1 to 2 percent. The stack O_2 was lowered from a baseline of 4.1 percent to an operating level of 2.6 percent.
- The savings of natural draft staged combustion air on a natural draft process heater applied at normal stack O_2 is calculated as \$714/Mg NO_x reduction for a 16.1 MW heater and increases to \$964/Mg at 147 MW heat input.
- The natural draft staged air system (3" lances) reduced NO emissions by approximately 30 percent (SCA and LEA) over a 15-day period. The reduction is achieved without operational problems (e.g., flame impingement, smoking, CO). The NO emissions reduction is based on lowering the stack oxygen from 4.0 percent to 2.0 percent.

TABLE 1-1. SUMMARY OF RESULTS OF COMBUSTION MODIFICATION TESTS ON A PILOT-SCALE PROCESS HEATER

Heat Input MW_T	Fuel Type	Baseline O_2 (%)	Combus. Modific. O_2 (%)	Baseline NO ng/J	Baseline NO ppm dry at 3% O_2	Percent Staging Air	NO Reduction from Baseline %	Change in Fuel Consumption, %	Combustion Modification
14.2	Ref. Gas	4	3.9	67	131	40	43	-1.1	ND (SCA) 4" ports
12.8	Ref. Gas	4.2	3.8	73	142	33	21	0	ND (SCA) 3" lances
12.9	Ref. Gas	3.6	3.4	70	138	8	12	+1.8	ND (SCA) 1-1/4" lances
15.6	Ref. Gas	4	2.0	78	152	--	21	-1.3	LEA (no staging)
14.4	Ref. Gas	4.1	2.6	78	152	45	46	-1.4	ND (SCA + LEA) 4" ports
10.7	80% Oil/20% Gas	3.8	3.8	135	265	41	25	-4.5	FD (SCA)
9.4	80% Oil/20% Gas	4.1	2.0	167	328	--	28	-2.4	LEA (4% → 2% O_2)
13.6	80% Oil/20% Gas	5.7	4.1	140	344	--	13	-2.5	LEA (5.7% → 4.1% O_2)
15.2	80% Oil/20% Gas	6.1	3	176	345	39	37	-6.0	FD (SCA + LEA) 6% → 3% O_2

SCA = Staged Combustion Air

LEA = Lowered Excess Air

ND = Natural Draft

FD = Forced Draft

- An automatic stack O_2 control system is necessary to maintain a low stack oxygen content with the staged air system and maintain the low oxygen content under all operating conditions.

- 80 percent oil/20 percent gas-fired testing showed that forced draft staged combustion air (6 percent stack O_2) lowered NO emissions by approximately the same amount (20-25 percent) as low excess air with no staging (6 percent → 4 percent O_2). The lower limit for stack oxygen with LEA only was achieved with damper adjustments and register adjustments.

- Lowered excess air together with staged combustion air reduced NO emissions by 40 percent (6 percent O_2 → 3 percent O_2) on a natural draft vertical cylindrical heater firing 80 percent oil/20 percent gas. The extra decrease in stack oxygen with the combined modification was attained by damper adjustments and optimizing the forced draft air system.

- The cost of natural draft staged combustion air combined with lowered excess air on a natural draft crude heater is calculated as $336/Mg NO reduction for a 16.1 MW unit and a savings $435/Mg NO reduction for a 147 MW unit. The cost at lower unit heat rates with the combined modification is due to the inclusion of an automatic stack draft controller to allow operation of the heater at lowered O_2.

SECTION 2.0

TEST EQUIPMENT DESCRIPTION

This section presents information on the forced draft and natural draft staged air injection, a description of the heater, its burners and the fuel gas system; and a discussion of emissions sampling equipment.

2.1 STAGED AIR SYSTEM

Two different types of staged air systems were designed for this program. Both a forced draft system and natural draft system were used during this program. The two systems are described below.

2.1.1 Staged Combustion Air System (Forced Draft)

This application of a staged combustion utilized air lances in the firebox to supply air to the flame zone a given distance above the base of the flame. Figure 2-1 presents a schematic of this system.

The system consisted of 24 vertical 316L stainless steel pipes 3.18 cm (1-1/4 in.) diameter arranged four-per-burner, 90 deg. apart. A 45-deg. elbow was placed on each pipe to provide better mixing across the flame. A fan supplied air to the lances through a manifold and flexible tubing. The lances could be varied in height up to 1.2 m (4 ft) from the floor of the heater. Extensions for the lances allowed staging heights up to 2.4 m (8 ft) for oil firing tests. The lances were placed on a 91.4 cm (36 in.) bolt circle around each of the six burners. The six burners were equally spaced on a 99.1 cm (39 in.) bolt circle around the vertical centerline of the heater.

The blower was capable of delivering a maximum air flow of 1.36 m^3/s 2875 scfm at velocities of up to 58 m/s (190 ft/sec) to the 24 lances. This air flow represented approximately 45 percent of the total combustion air for the heater operating conditions of 80 percent fuel oil/20 percent gas firing at a crude charge rate of 11,500 bbl/day. The blower is the same high

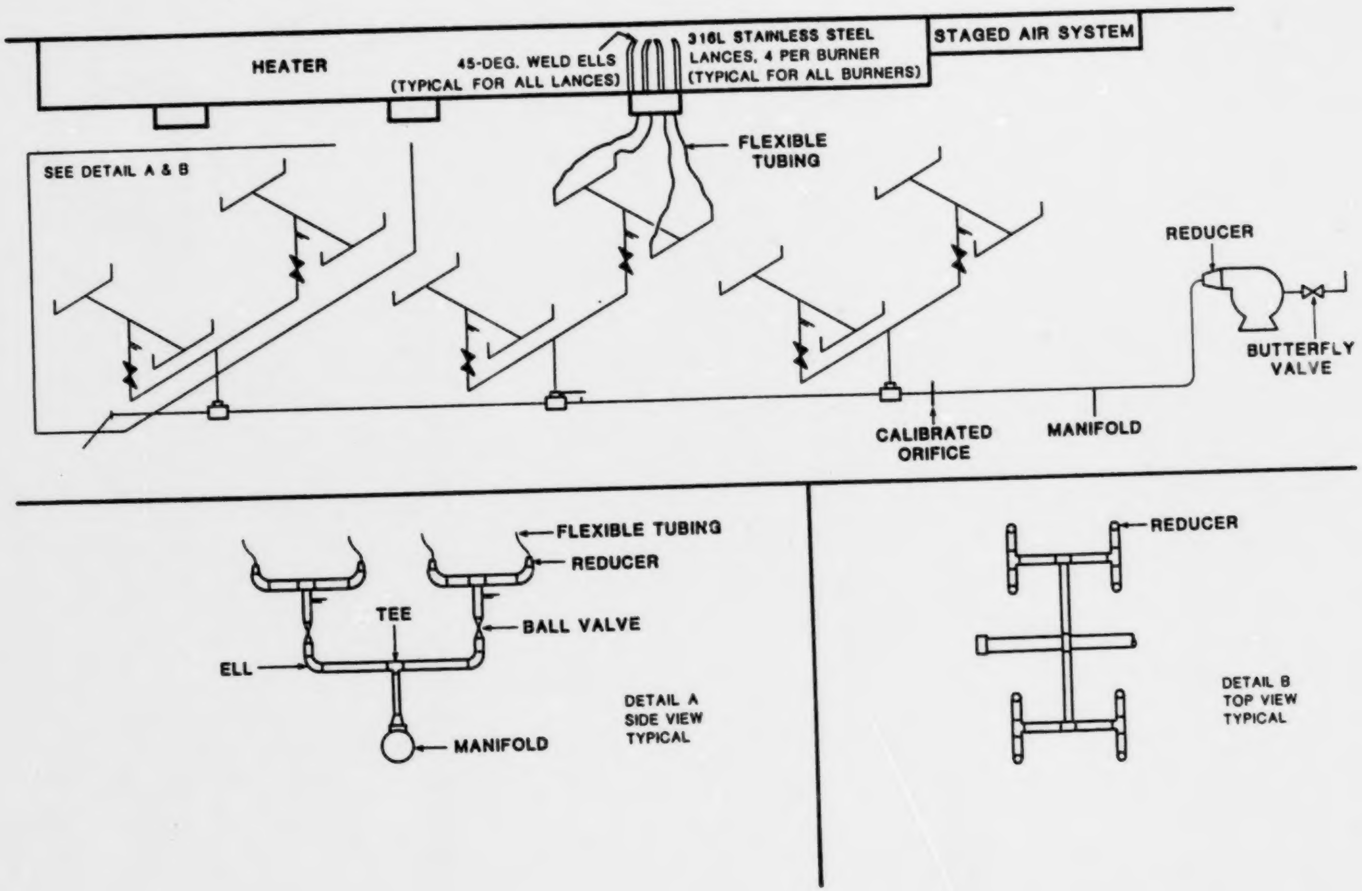
HEATER
45-DEG. WELD ELLS
(TYPICAL FOR ALL LANCES)
316L STAINLESS STEEL
LANCES, 4 PER BURNER
(TYPICAL FOR ALL BURNERS)
STAGED AIR SYSTEM
FLEXIBLE
TUBING
SEE DETAIL A & B
REDUCER
BUTTERFLY
VALVE
CALIBRATED
ORIFICE
MANIFOLD
FLEXIBLE TUBING
REDUCER
TEE
BALL VALVE
ELL
MANIFOLD
DETAIL A
SIDE VIEW
TYPICAL
REDUCER
DETAIL B
TOP VIEW
TYPICAL

Figure 2-1. Flow schematic of staged combustion air system for a natural draft process heater.

pressure ILG Industries Model R33Y type with a 74.6 kW (100 hp) totally enclosed, fan cooled (TEFC) motor. The TEFC motor was required by refinery standards. Total staged combustion air flow was measured by means of a pitot tube in the 25 cm (8 in.) duct at the blower discharge. Flow was also measured to each burner by pitot tubes in the 7.6 cm (3 in.) risers just upstream of the split to the four lances. The flow of air to each burner could be controlled by means of ball valves as shown in Figure 2-1.

2.1.2 Staged Combustion Air System (Natural Draft)

Holes were drilled through the heater floor such that one end of the 4-in. pipe would be flush against the heater floor and the other end (threaded for pipe caps) would protrude a few inches below heater floor. For the natural draft staged air tests, the pipe caps would be removed and either 1-1/4 in. lances, 3-in. lances, or the 4-in. ports could be used.

2.2 TEST HEATER DESCRIPTION

The test unit is a natural draft, vertical cylindrical crude oil process heater which is used to supply a heated charge to a crude oil distillation column. A maximum load of 108 m^3/h (16,250 bbl/d) could be sent through the heater in two passes. The rated capacity of the heater is 91.8 m^3/h (14,000 bbl/day). A sketch of this crude oil heater is presented in Figure 2-2.

The maximum firing rate of the heater is 16.1 MW thermal input (55 x 10^6 Btu/hr). It is fired by six John Zink DBA-22* natural draft burners. The burners are combination gas/oil burners rated at a maximum of 2.68 MW (9.14 x 10^6 Btu/hr) each with a turndown ratio of 3:1. Although combination gas/oil burners are used, some gas is always fired because the unit is base loaded on oil fuel and an automatic temperature controller adjusts the gas fuel flow to maintain crude oil outlet temperature. During tests in which both gas and oil were fired simultaneously, each burner fired approximately the same fuel

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*Mention of trade names does not constitute endorsement by the Environmental Protection Agency.

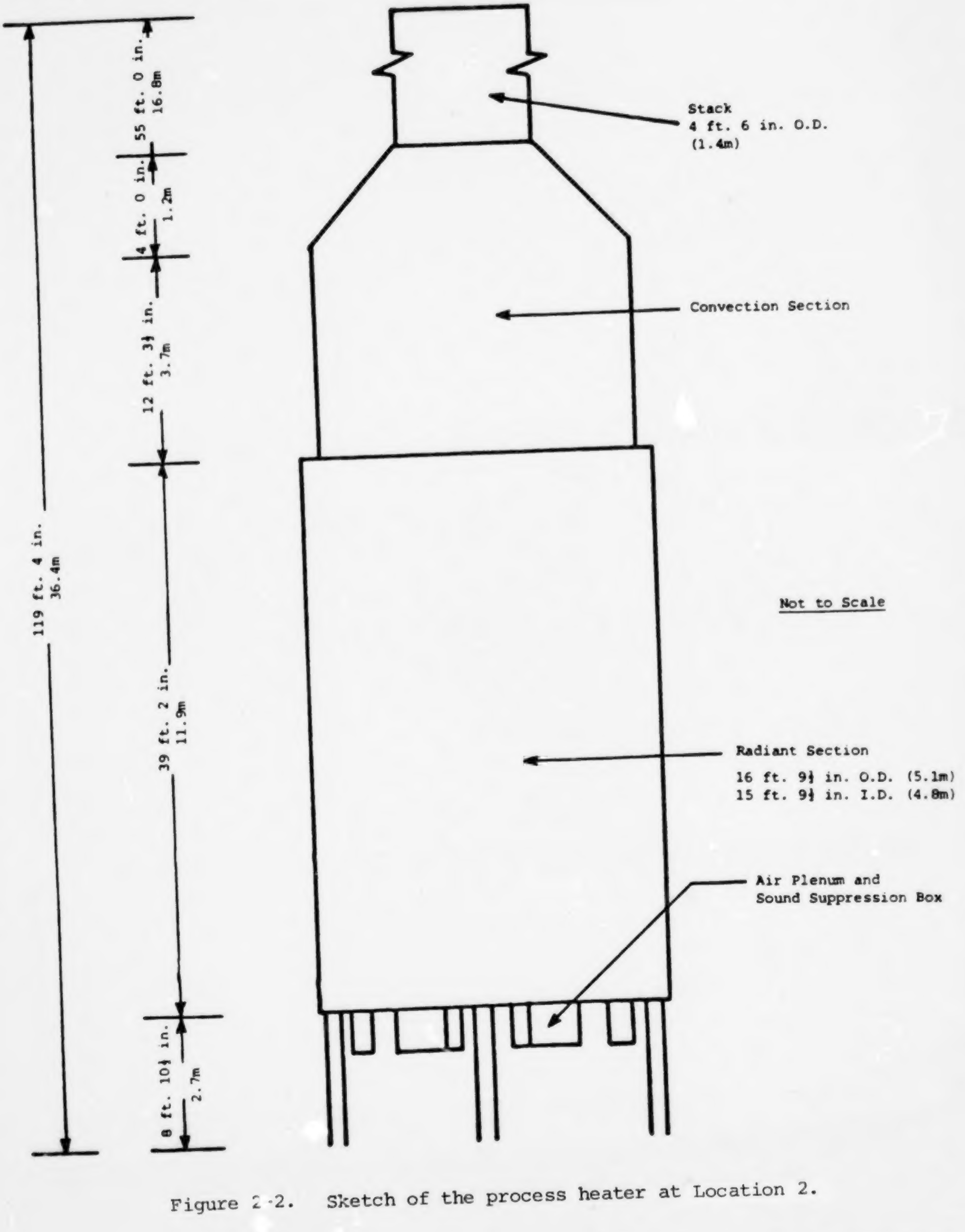
55 ft. 0 in.
16.8m
4 ft. 0 in.
1.2m
12 ft. 3½ in.
3.7m
39 ft. 2 in.
11.9m
8 ft. 10½ in.
2.7m
119 ft. 4 in.
36.4m
Stack
4 ft. 6 in. O.D.
(1.4m)
Convection Section
Not to Scale
Radiant Section
16 ft. 9½ in. O.D. (5.1m)
15 ft. 9½ in. I.D. (4.8m)
Air Plenum and
Sound Suppression Box

Figure 2-2. Sketch of the process heater at Location 2.

split. Plan and elevation views of the burners used are shown in Figures 2-3a and 2-3b.

Figure 2-4 shows the gas fuel sources and fuel flow paths for the crude heater. The fuel gas line to the heater consists of two branches. One branch is the absorber gas and the other is called the plant fuel gas line. The absorber gas is refinery gas which has passed through an absorber column. This column is a caustic acid solution which removes the CO_2 and H_2S from the gas stream. The plant fuel gas can consist of any or all of the following components:

- LPG + Crude Vapors
- Gases from #2 Fuel Gas Drum
- Propane from Depropanizer Accumulator
- Western Gulf Gas
- Reabsorber Dry Gas (Nonscrubbed)
- Southern Cal Gas

The volumetric flow rates for reabsorber gas and plant fuel gas are measured by orifice meters and recorded on chart.

Most of the time, absorber gas (scrubbed refinery gas) is burned in the heater. If the absorber column is down for maintenance, plant fuel gas will then be burned in the heater.

Three parameters could be controlled in the heater: excess oxygen (by furnace draft), firing rate, and load. The stack damper was the main control for the pressure drop across the furnace. The pressure drop could also be controlled by opening or closing the secondary air registers on each burner. A sound-suppression chamber installed on the bottom of the heater permitted access to the secondary air registers. The primary air to the burners was controlled by louvers on the bottom of the sound-suppression chamber. The stack damper and register adjustments established the excess oxygen. The load was controlled by pumps and valves on the inlet and outlet of the heater.

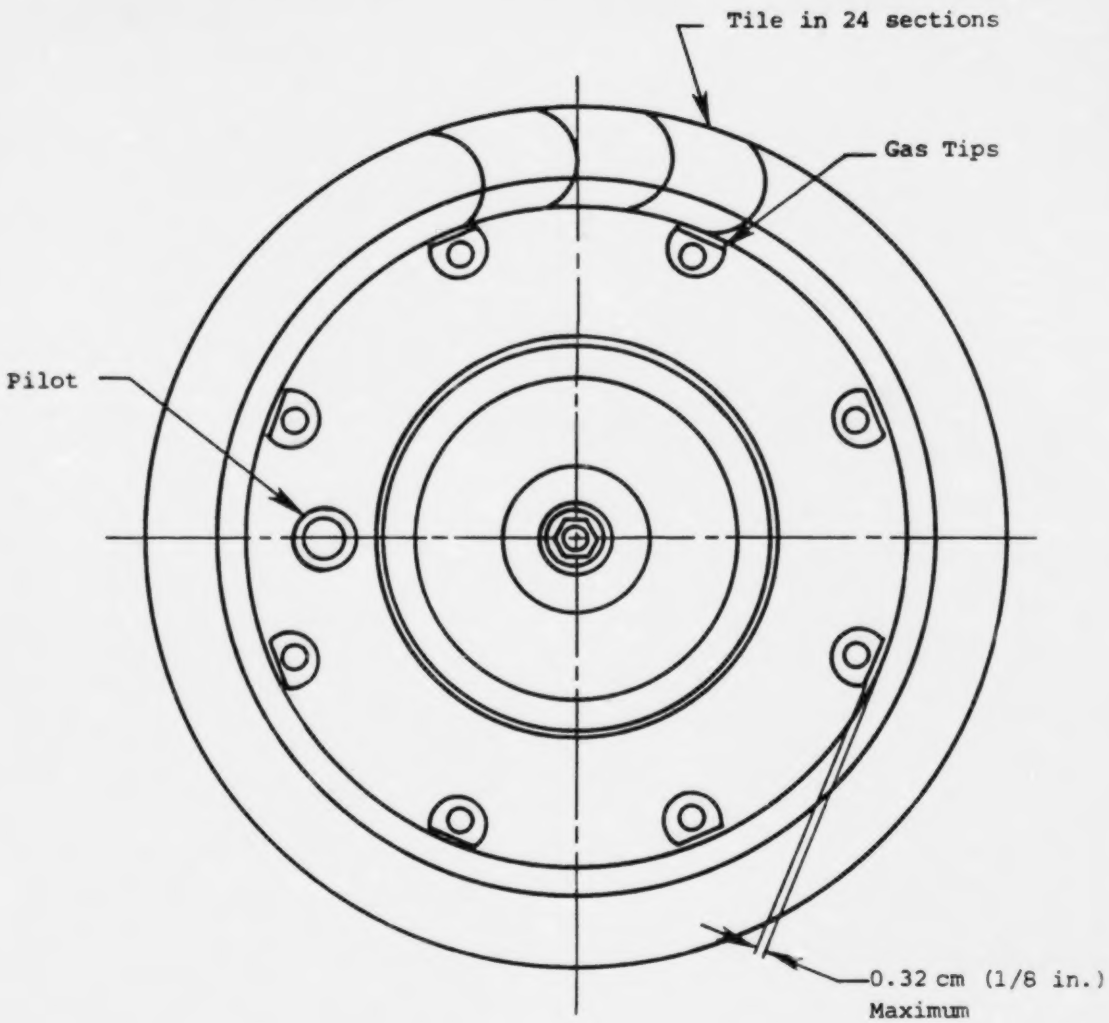
Tile in 24 sections
Gas Tips
Pilot
0.32 cm (1/8 in.)
Maximum

Figure 2-3a. Plan view of DBA-22 combination oil/gas burner used in test heater (courtesy of John Zink Co.)

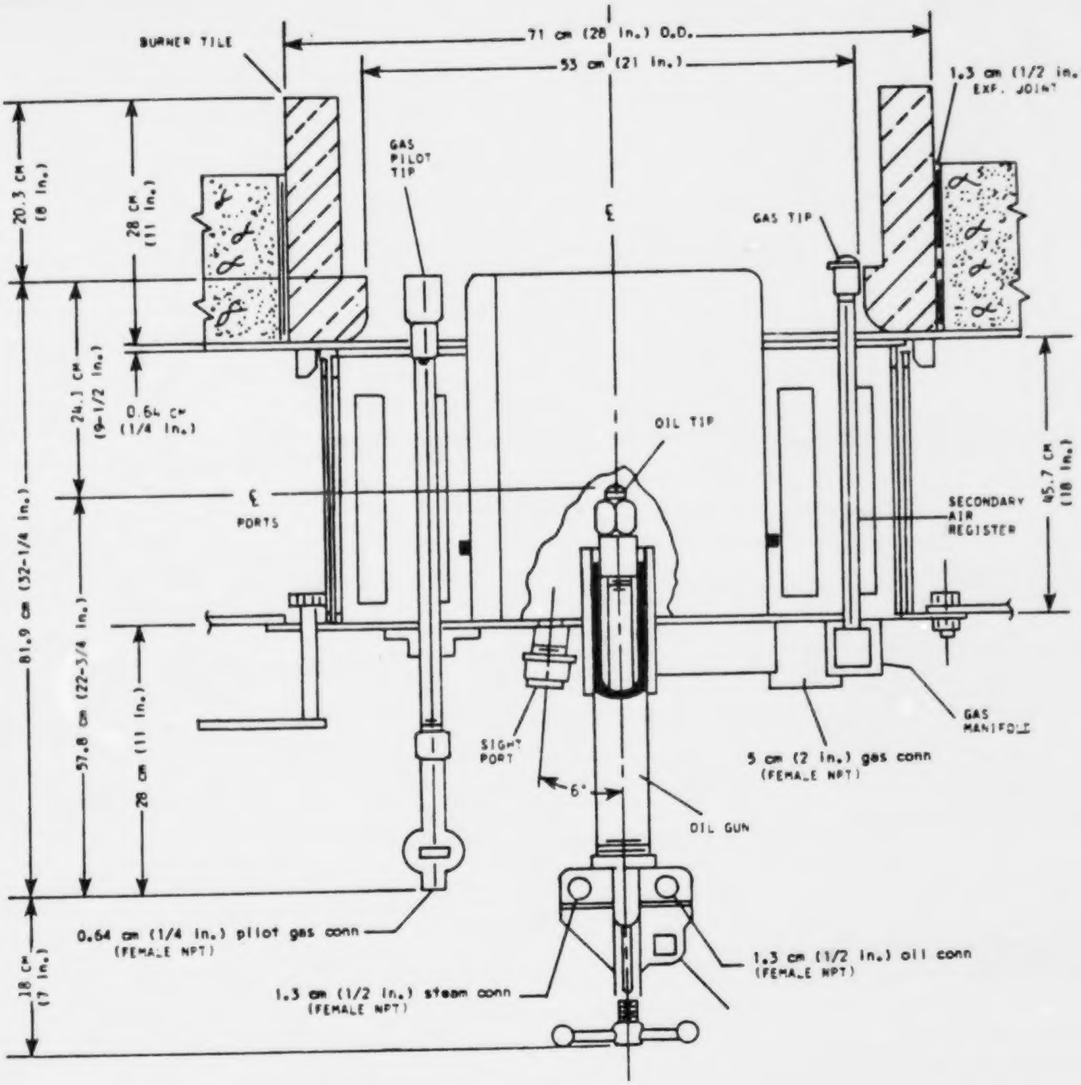
BURNER TILE
71 cm (28 in.) O.D.
53 cm (21 in.)
1.3 cm (1/2 in.) EXP. JOINT
GAS PILOT TIP
GAS TIP
℄
20.3 CM (8 in.)
28 CM (11 in.)
24.1 CM (9-1/2 in.)
0.64 CM (1/4 in.)
OIL TIP
℄ PORTS
SECONDARY AIR REGISTER
45.7 CM (18 in.)
81.9 cm (32-1/4 in.)
57.8 cm (22-3/4 in.)
28 cm (11 in.)
GAS MANIFOLD
SIGHT PORT
6°
5 cm (2 in.) gas conn (FEMALE NPT)
OIL GUN
0.64 cm (1/4 in.) pilot gas conn (FEMALE NPT)
1.3 cm (1/2 in.) oil conn (FEMALE NPT)
1.3 cm (1/2 in.) steam conn (FEMALE NPT)
18 CM (7 in.)

Figure 2-3b. Part sectional elevation of DBA-22 burner (courtesy of John Zink Co.)

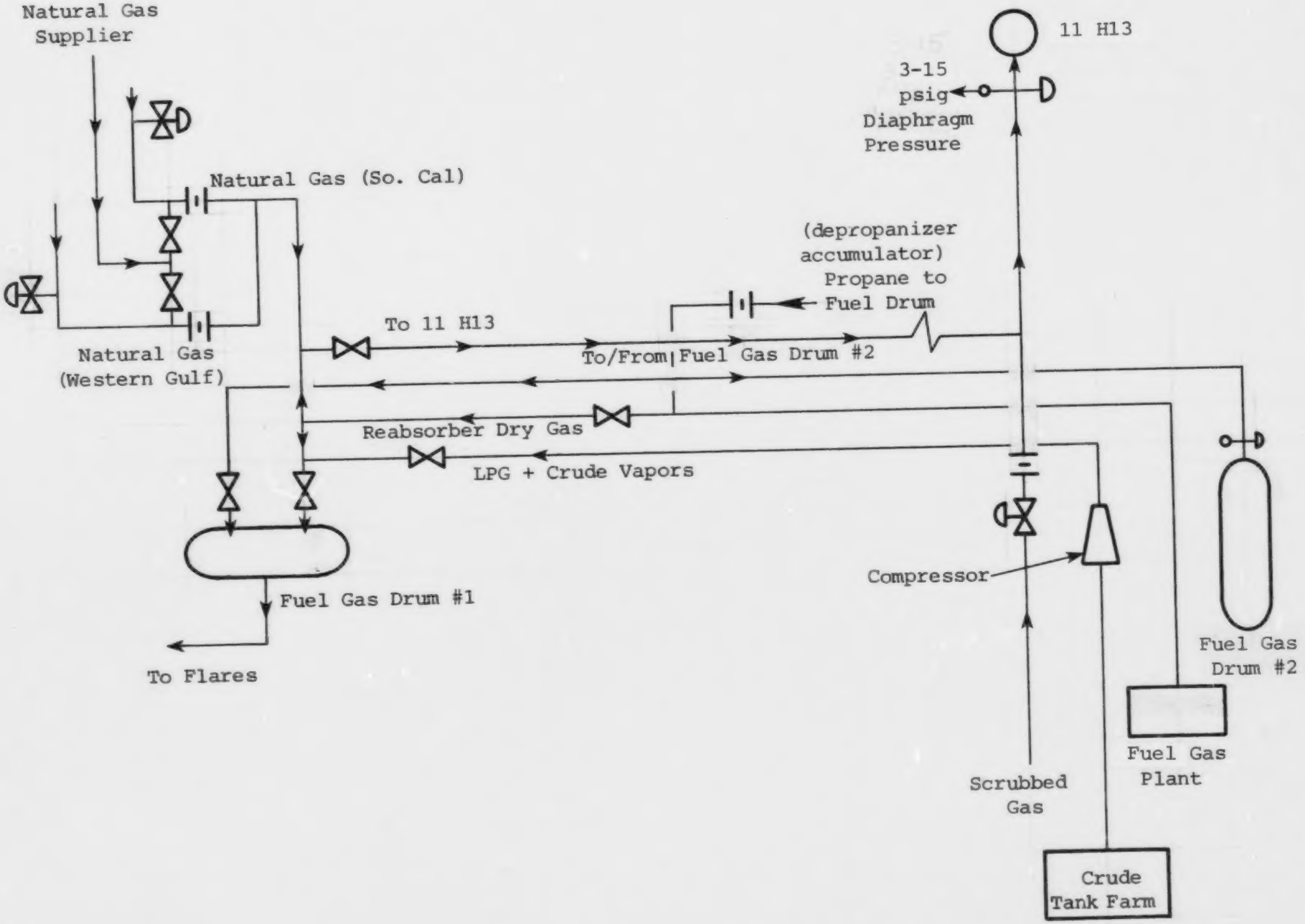
Natural Gas Supplier
Natural Gas (So. Cal)
Natural Gas (Western Gulf)
11 H13
3-15 psig Diaphragm Pressure
(depropanizer accumulator) Propane to Fuel Drum
To 11 H13
To/From Fuel Gas Drum #2
Reabsorber Dry Gas
LPG + Crude Vapors
Fuel Gas Drum #1
To Flares
Compressor
Scrubbed Gas
Fuel Gas Drum #2
Fuel Gas Plant
Crude Tank Farm

Figure 2-4. Fuel Gas Flow Schematic to Heater

This heater was chosen because of its simple design and flexibility of operation. (Temperature profiles in crude heaters are not as critical as in other stages of the refining process.) Further, the unit contained John Zink burners which were nearly identical to those tested in the prior pilot scale program mentioned earlier (Ref. 2). This allowed direct application of the experience gained at the pilot-scale level.

2.3 EMISSIONS SAMPLING EQUIPMENT

Gaseous emission measurements were made using analytical instruments and equipment contained in a government-furnished mobile instrumentation laboratory. Total particulate measurements were made using an EPA Method 5 sampling train manufactured by Andersen Samplers, Inc. Particulate size distribution was measured using an Andersen Mark III Cascade Impactor. Total oxides of sulfur were measured by wet chemistry methods using the sampling train and analytical procedure of the Goksoyr-Ross method. Smoke density was measured using an automated Bacharach smoke spot pump. Stack opacity readings were made during particulate tests according to EPA Method 9. N_2O is measured by G/C.

2.3.1 Gaseous Emissions Sampling System

The laboratory is equipped with analytical instruments to continuously measure concentrations of NO, CO, CO_2, O_2, and SO_2. The sample gas is delivered to the analyzers at the proper condition and flow rate through the sampling and conditioning system described below. Appendix A describes the analytical instrumentation and the details of the sampling system. Also, a flow schematic and description of the flue gas sampling and analyzing system is presented in detail in Appendix A. Briefly, the sampling system used pumps to continuously draw flue gas from the heater into the laboratory. A high-capacity heated positive displacement diaphragm pump was used to draw a high volume of flue gas into the analyzers thereby providing adequate system response.

Special precautions are required to obtain a representative sample for the analysis of SO_2. These precautions consisted primarily of insuring that the sample was kept above its dew point, since these constituents are quite soluble in water. For this reason, an electrically heated 9.5 mm (3/8 in.) Teflon sample line was used to bring the sample into the laboratory for analysis. The hot pump provided heated sample directly to the hydrocarbon, SO_2, and NO_x analyzers.

A portion of the sample pump discharge was also sent through a refrigerated condenser [to reduce the dew point to 275 K (35°F)], through a large rotameter with flow control valve, and then to the O_2, NO, CO, and CO_2 instrumentation. Flow to each individual analyzer was measured and controlled with smaller rotameters and flow control valves. Excess sample was vented outside the laboratory.

2.3.2 Particulate Emissions

Particulate samples were taken at the same sample location as the gas sample using an Andersen Samplers, Inc. portable effluent sampler. These tests were made at baseline and optimum low-NO_x operating conditions. This system, which meets EPA design specifications for Test Method 5, Determination of Particulate Emissions from Stationary Sources (Federal Register, Volume 36, No. 27, page 24888, December 23, 1971) was used to perform both the initial velocity traverse and the particulate sample collection. Dry particulates were collected in a heated case that contained a 110 mm glass-fiber filter for retention of particles down to 0.3 micrometers. Condensible particulates are collected in a train of four impingers in a chilled water bath.

Particle size was measured at baseline and optimum low-NO_x conditions at the same sample location as the Method 5 tests. An Andersen Mark III Cascade Impactor was used for all of the sizing tests because of its high-volume/low grain loading capability. This impactor was capable of fractionating particles in situ into nine aerodynamic size ranges (eight collection stages and one backup filter). The size range capability of this impactor was approximately 0.4 μm to 10 μm.

The Method 5 sampling train and procedures, and the impactor operational procedures, are discussed in Appendix A.

2.3.3 Wet Chemical SO_x Measurement

The Goksoyr-Ross technique was used to sample the stack gas for SO_3. This method uses controlled condensation of the stack gases in a coil maintained at 333-344 K (140-160°F) by a water bath. This temperature is below the sulfuric acid (H_2SO_4) dewpoint so that the SO_3 and the water vapor in the flue gas condense upon the coil walls to form H_2SO_4 droplets. The SO_2 in the flue gas passes through the coil and is collected in impingers containing a weak hydrogen peroxide solution. Following the impingers, the flue gas flows through a dry gas meter and is then discharged into the atmosphere.

The coil rinse and impinger liquid are each analyzed by means of an acid-base titration with a sodium hydroxide solution. Thus, both the SO_3 and SO_2 concentrations may be determined from this procedure.

2.3.4 Smoke Spot and Opacity Measurement

On combustion equipment where smoke numbers normally are taken, such as oil-fired boilers, KVB, Inc. determines the smoke number using test procedures according to ASTM Designation: D 2156-65. The smoke number is determined at each combustion modification setting of the unit. Examples are baseline, minimum excess air, low load, etc., and whenever a particulate concentration is measured.

Smoke spots are obtained by pulling a fixed volume of flue gas through a fixed area of a standard filter paper. The color (or shade) of the spots that are produced is visually matched with a standard scale. The result is a "Smoke Number" which is used to characterize the density of smoke in the flue gas.

Opacity readings are taken by a field crew member who is a certified graduate of a U.S. Environmental Protection Agency approved "Smoke School." Observations are made at the same time that particulate measurements are made and as often in addition as deemed necessary to gather the maximum amount of information. The procedures set forth in EPA Method 9, "Visual Determinations of the Opacity of Emissions for Stationary Sources," are followed.

2.3.5 N_2O Measurement

Samples are collected by expanding the stack gases into evacuated 2-liter Pyrex flasks fitted with grease-free O-ring stopcocks. Prior to sampling, the flasks were baked for four hours at 200°C under high vacuum. Duplicate flask samples were collected for baseline and low-NO_x operating conditions firing the 80/20 oil/gas mixture. The samples are analyzed by gas chromatographic measurement of the N_2O/CO_2 or N_2O/O_2 ratio.

2.3.6 Recording Instrumentation

An on-line Emissions Monitor Program was written for the Apple II Plus 48K computer to provide automatic digital data acquisition for real time monitoring of emissions data. The data logger was programmed to scan every five seconds and print the gaseous emissions data every one, three, or five minutes. The program provides a continuous visual display of time plots for two gaseous species (e.g., NO, O_2) and records the data printed out on magnetic disk. Strip chart recorders are used to verify the data recorded on magnetic disk and fill in any gaps from the data logger, should they occur.

SECTION 3.0

RESULTS OF COMBUSTION MODIFICATION TESTS WITH GAS FIRING

The following sections present test data for the crude heater firing 100 percent gas. Baseline data (without combustion modifications) and modified heater operations (natural draft staged combustion air only) are discussed in regards to NO emissions and heater efficiency. A complete data summary of these process heater tests is provided in Appendix B. Gas analyses are presented in Appendix D.

3.1 HEATER PERFORMANCE (NO STAGING AIR)

Prior to the start of the test program with the natural draft lances, two consecutive days of baseline data were gathered for the crude heater operating at approximately 80 percent of rated capacity. The baseline data included gaseous emissions and thermal efficiency. These baseline tests were conducted with a scrubbed refinery off gas from an absorber. Baseline operation was conducted with the four-inch pipe caps (no SCA) on and the average setting on the secondary air registers was approximately 50 percent open.

Average baseline NO emissions were 126 ppm, dry, corrected to 3 percent O_2 (64 ng/J) and the standard deviation was 3.5 ppm. The efficiency of the crude heater was 72 percent based on the abbreviated ASME heat loss method. Figure 3-1 shows the mean and standard deviation NO and O_2 concentrations over the duration of the long-term baseline testing. The crude feed rate was 75.1 m^3/hr (11,300 bbl/day) and the stack gas O_2 was approximately 4 percent for these long-term baseline tests.

For each series of tests where an independent variable was adjusted (load, staging height, injection area, and stack oxygen percent) for the natural draft staged air system, at least one baseline test was run to determine the percentage NO reduction with the independent variable change.

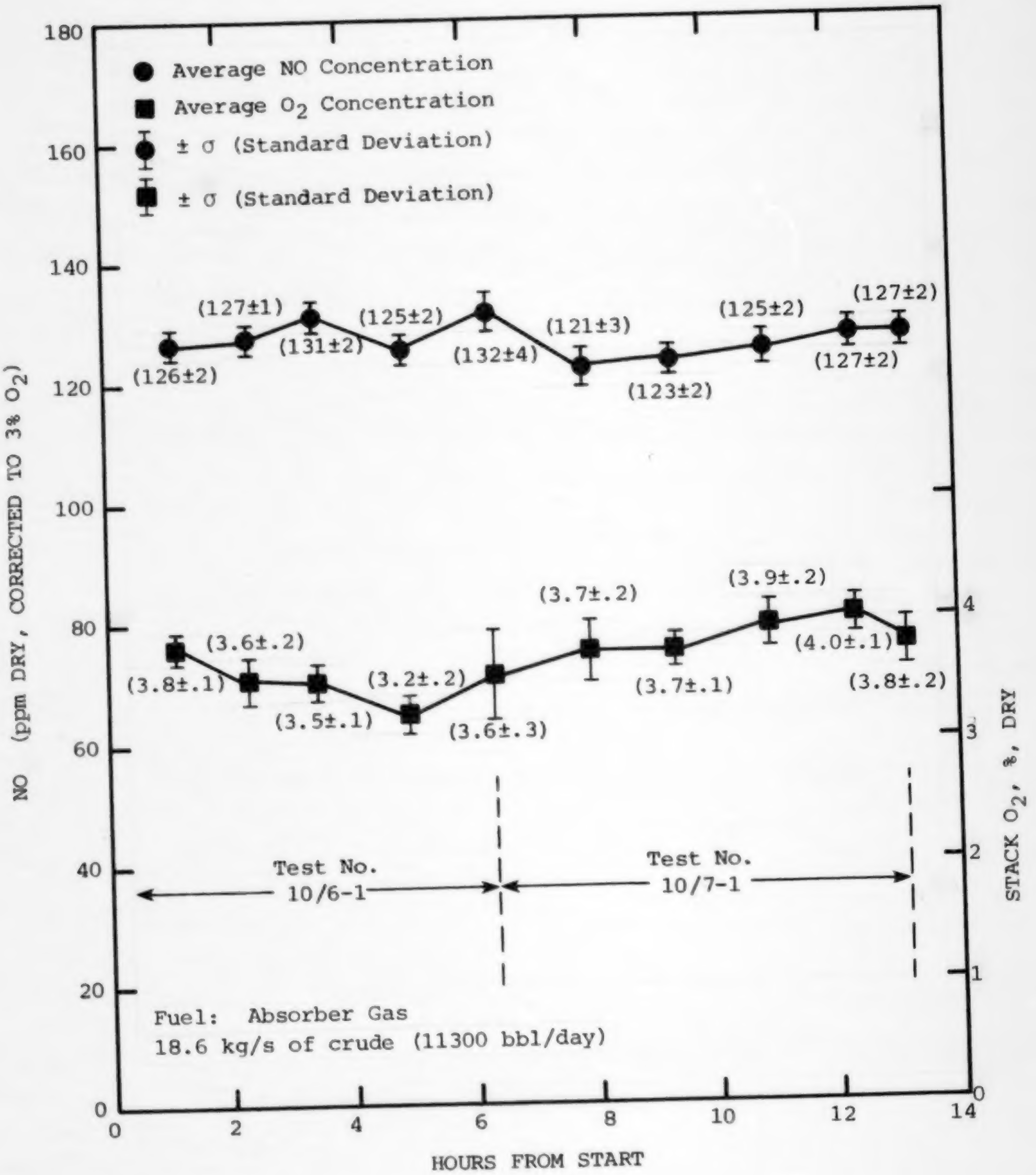

Figure 3-1. Long-term Baseline NO and O_2 Emissions (Absorber Gas Firing)

Daily baseline tests were conducted with 100 percent absorber gas (scrubbed refinery gas), 100 percent non-scrubbed refinery gas ("fuel gas") mixed with natural gas, and a mixture of refinery gas and fuel gas. Since most of the test series were conducted at 76 m^3/hr process rate (11,500 bbl/day), the daily baseline NO emissions for these test series were plotted as a function of stack oxygen for this particular process rate. Figure 3-2 shows the linear regression curve of NO versus stack oxygen with no combustion modifications. The linear regression of the data shows a fairly good coefficient of determination $r^2 = 0.59$. Deviations may be due to small changes in the absorber gas fuel constituents which may affect NO emissions. Secondary air registers were typically 50 percent open at 4 percent stack oxygen and 10 percent open at 2 percent stack oxygen.

3.2 EVALUATION OF THREE STAGING AIR CONFIGURATIONS

Three staged air injection configurations were tested using 4-inch ports, 3-inch pipes, and 1-1/4-inch pipes, respectively. The physical limit for a port diameter size drilled through this test heater floor and refractory was 4 inches. The ports were flush with the heater floor whereas the pipes could be inserted through the ports to introduce the staging air at a higher distance above the heater floor. Load was maintained nominally at 80 percent rated capacity and stack oxygen of 4 percent for testing with the three injection configurations. The injection area of 24 4-inch ports provided approximately 45 percent of the combustion air. This operating condition was implemented with secondary air registers only 10 to 30 percent open. The smaller lance diameters could not provide the same proportion of staging air, even with secondary air registers 10 percent open. Table 3-1 shows the effective lance area, percentage combustion air, and staging heights associated with the lance diameter. For all tests conducted with these lance diameters, CO levels were minimal and flame impingement was not a problem.

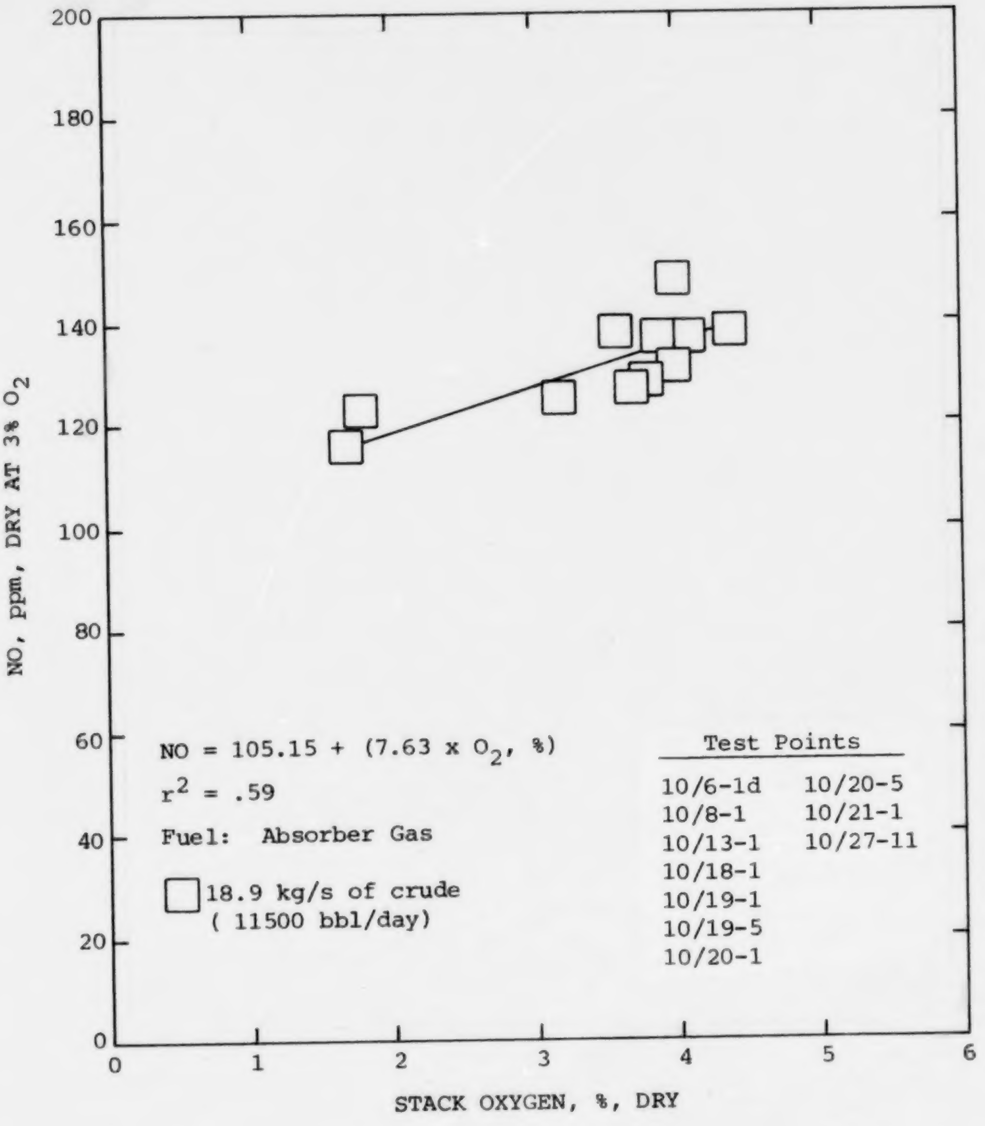

Figure 3-2. Baseline NO emissions as a function of stack oxygen for a natural draft process heater firing a scrubbed refinery gas (absorber gas).

TABLE 3-1. STAGING AIR INJECTION SPECIFICATIONS AND OPERATION

Normal Pipe Size	Total Area m^2/ft^2 (24 lances)	% Combustion Air	Staging Ht (m/ft)
4"	0.20/2.12	40	0.1/0.4
3"	0.11/1.23	33	0.6, 1.2/2,4
1-1/4"	0.02/0.25	8	1.2/4

Operating Conditions:

Crude Charge Rate:	76 m^3/hr (11,500 bbl/d)
Heat Input:	(12.8 - 14.2 MW)
Stack O_2:	4 percent

Four-inch ports achieved the greatest NO reduction (Figure 3-3). A reduction of approximately 45-50 percent was achieved from baseline conditions (SCA only). The burner equivalence ratio, defined as

$$\Phi_B = \frac{(\text{air/fuel})_{\text{burner}}}{(\text{air/fuel})_{\text{stoichiometric}}}$$

was approximately 0.72 with secondary air registers 10 percent open. At this minimum Φ_B, NO emissions decreased 47 percent below the baseline of 131 ppm dry at 3 percent O_2 (67 ng/J).

Three-inch lances showed only a modest 15-20 percent NO reduction from baseline conditions with SCA only (Figure 3-3). The minimum burner equivalence ratio with these lances was approximately 0.82. Staging heights of 2 and 4 feet were also tried and showed approximately the same NO reduction levels.

A staging height of 4 feet was used to inject the air through the 1-1/4 inch diameter lances. The lance tips were oriented toward the vertical centerline of the heater. This orientation was used since previous testing (EPA Contract No. 68-02-2645) had shown this orientation to be the optimum for reducing NO_x emissions and minimizing flame impingement on the process tubes.

Figure 3-4 shows the percent NO reduction versus percent staging air for 3-inch lances and 4-inch ports. The purpose of this figure is to show that the 4-inch ports had the capability of providing more staging air and thus providing more NO reduction than the 3-inch lances. The curves show that if the lances had the capability of providing more staging air, the extent of NO reduction should be comparable with that of the 4-inch ports.

The 1-1/4 inch lances showed minimal NO reduction (approximately 10 percent). No staging could be achieved with 1-1/4 lances since the effective flow area was too small. Natural draft could not draw enough air through the lances to lower the Φ_B below 1.0.

During these tests with the three staged air injection configurations, furnace draft measurements along with firebox tube skin temperatures and stack

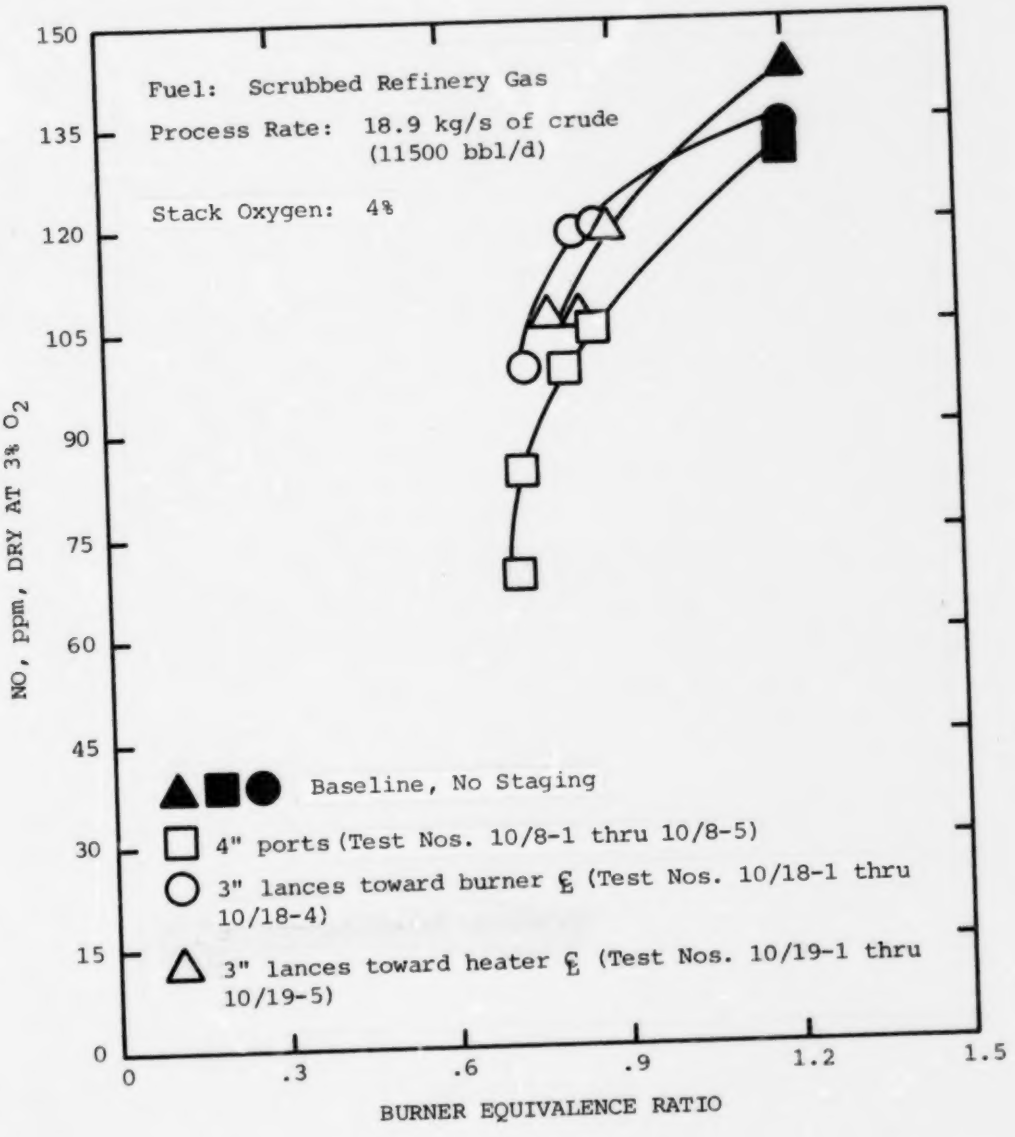

Figure 3-3. NO emissions versus burner equivalence ratio for 3" lances and 4" ports (natural draft staging air).

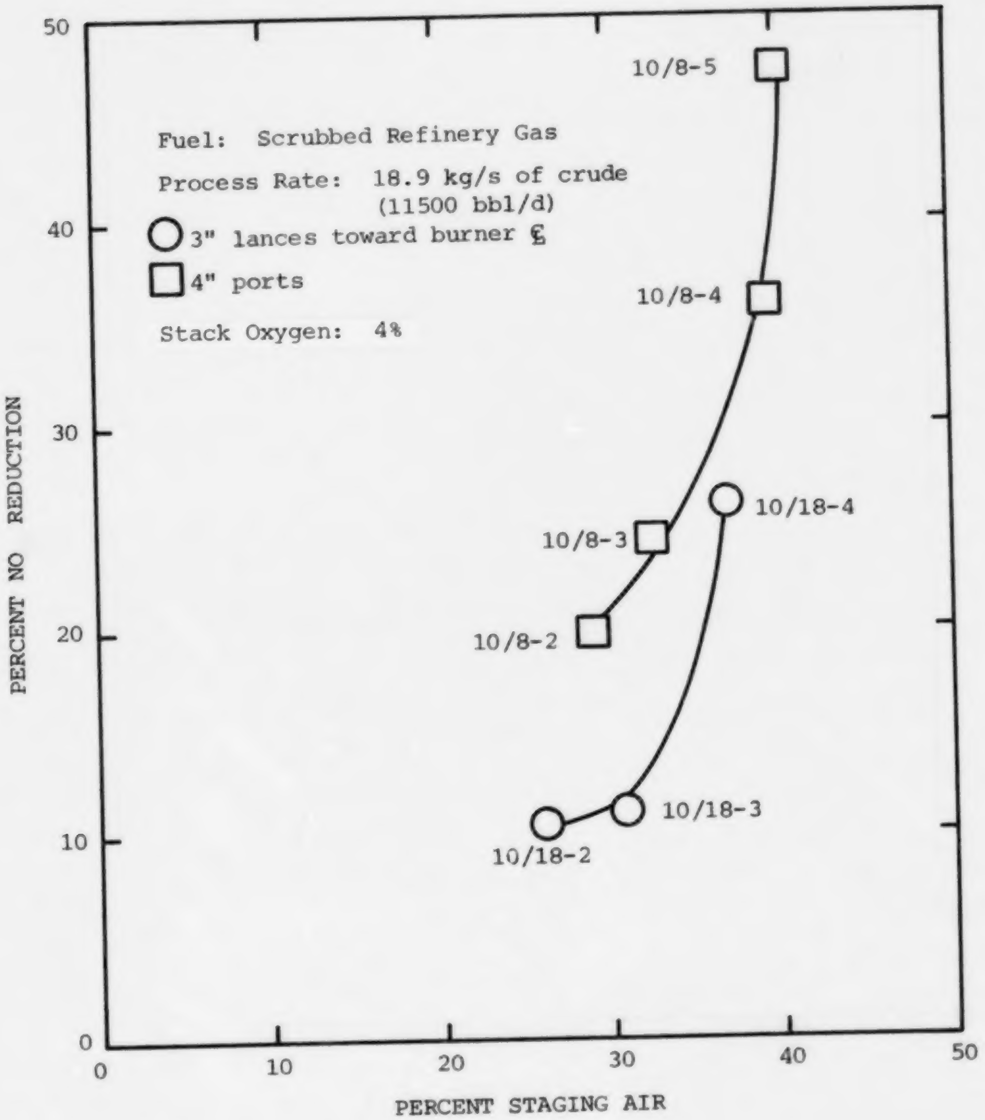

Figure 3-4. Percent NO reduction versus percent staging air for 3" lances and 4" ports.

temperatures were recorded. Figure 3-5 shows the effect of closing secondary air registers on furnace draft for a constant oxygen level of 4 percent. As expected, furnace draft increased (more negative) with closing the secondary air registers and decreased with the injection area. Firebox tube skin temperatures, located approximately 11 feet above the heater floor, showed an increase of approximately 15°F from the baseline condition to registers 10 percent open. This small delta indicates that temperature and heat flux distributions do not seem to be adversely affected under these operating conditions. Also the furnace draft was sufficiently high under all operating conditions providing no danger of pressurizing the firebox.

3.3 STAGED AIR SYSTEM: O_2 VARIATION, LOAD VARIATION

Since the 4-inch ports had provided the most staging and NO reduction of the three lance diameters tried, further testing with load variations and O_2 variations were conducted with the 4-inch ports. The three loads tested were 55, 80, and 90 percent rated capacity with O_2 variation from approximately 2 to 6 percent stack oxygen. Under these conditions, the CO concentration levels measured were minimal and flame impingement was not a problem.

Figures 3-6, 3-7, and 3-8 show the variation of NO with O_2 for the 55, 80, and 90 percent rated capacity loads, respectively. NO variations with O_2 are shown for three different air registers settings (50 percent, 33 percent, and 10 percent open). At the lower excess air levels (approximately 2 percent stack oxygen), the difference of air register settings between 33 percent open to 10 percent open on NO emissions is insignificant. With stepwise increases in stack oxygen levels, the differences between NO levels and register settings become more pronounced. The greater amount of staging provided by the burner air registers 10 percent open was the most effective setting overall for NO reduction. For all conditions run, furnace draft was checked to make sure the firebox was not pressurized. The maximum increase in tube skin temperature for any one test series was approximately 50°F.

Figure 3-9 shows the effect of staging (decreased burner equivalence ratio) on NO emissions. The crude charge rate for this test series was

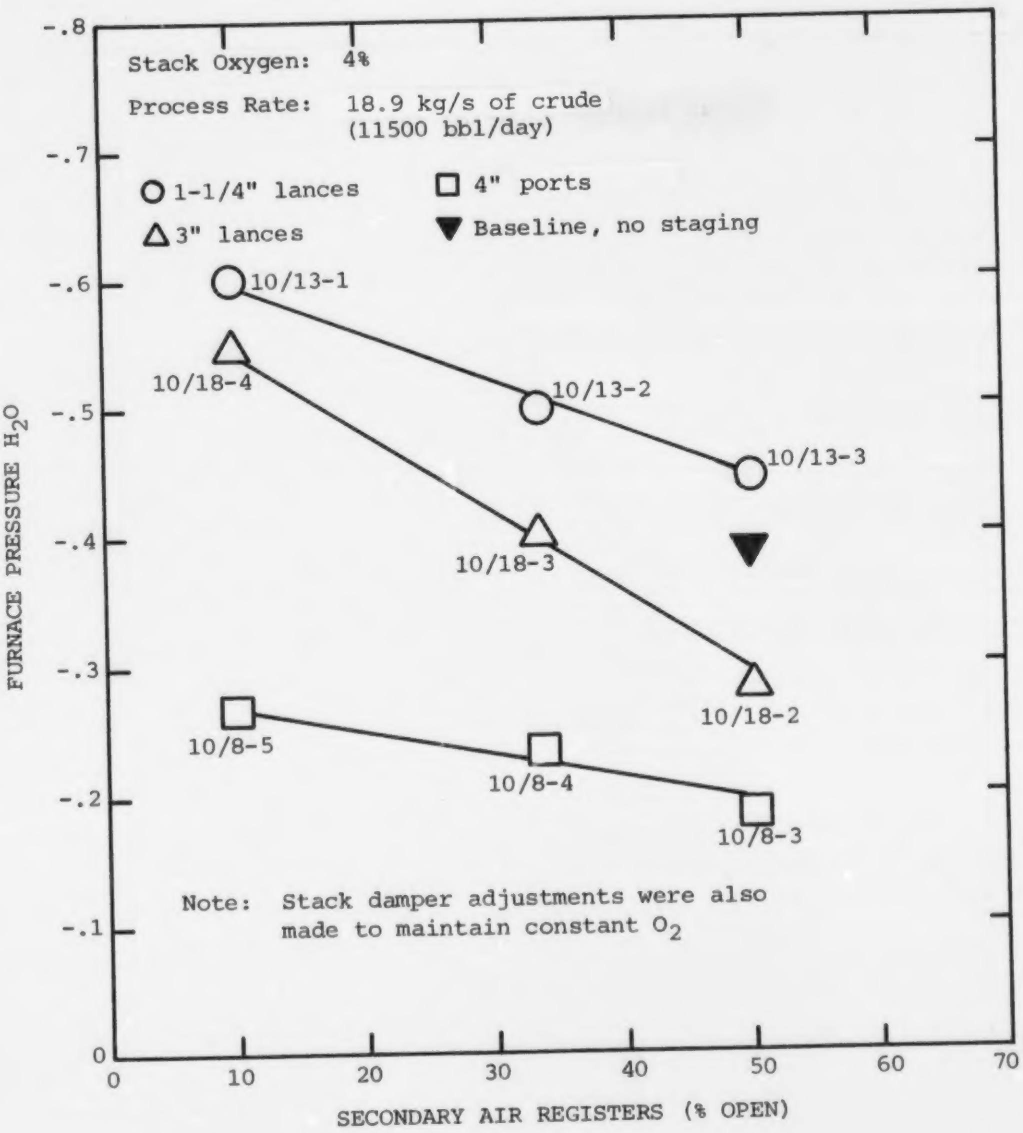

Figure 3-5. Furnace Draft versus Secondary Air Register Setting

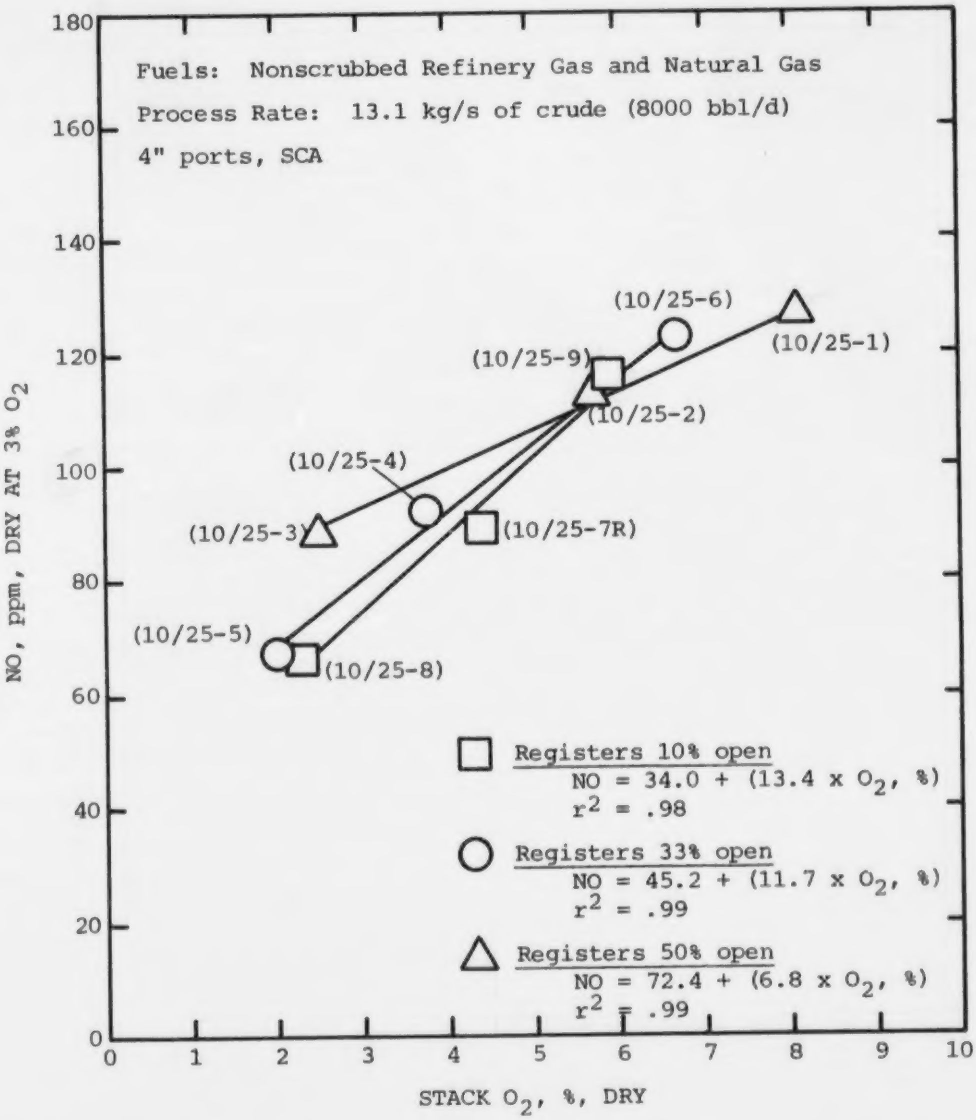

Figure 3-6. NO emissions at three secondary air register settings as a function of stack oxygen for a natural draft process heater with naturally drafted staged combustion air. (13.1 kg/s, 8000 bbl/d process rate)

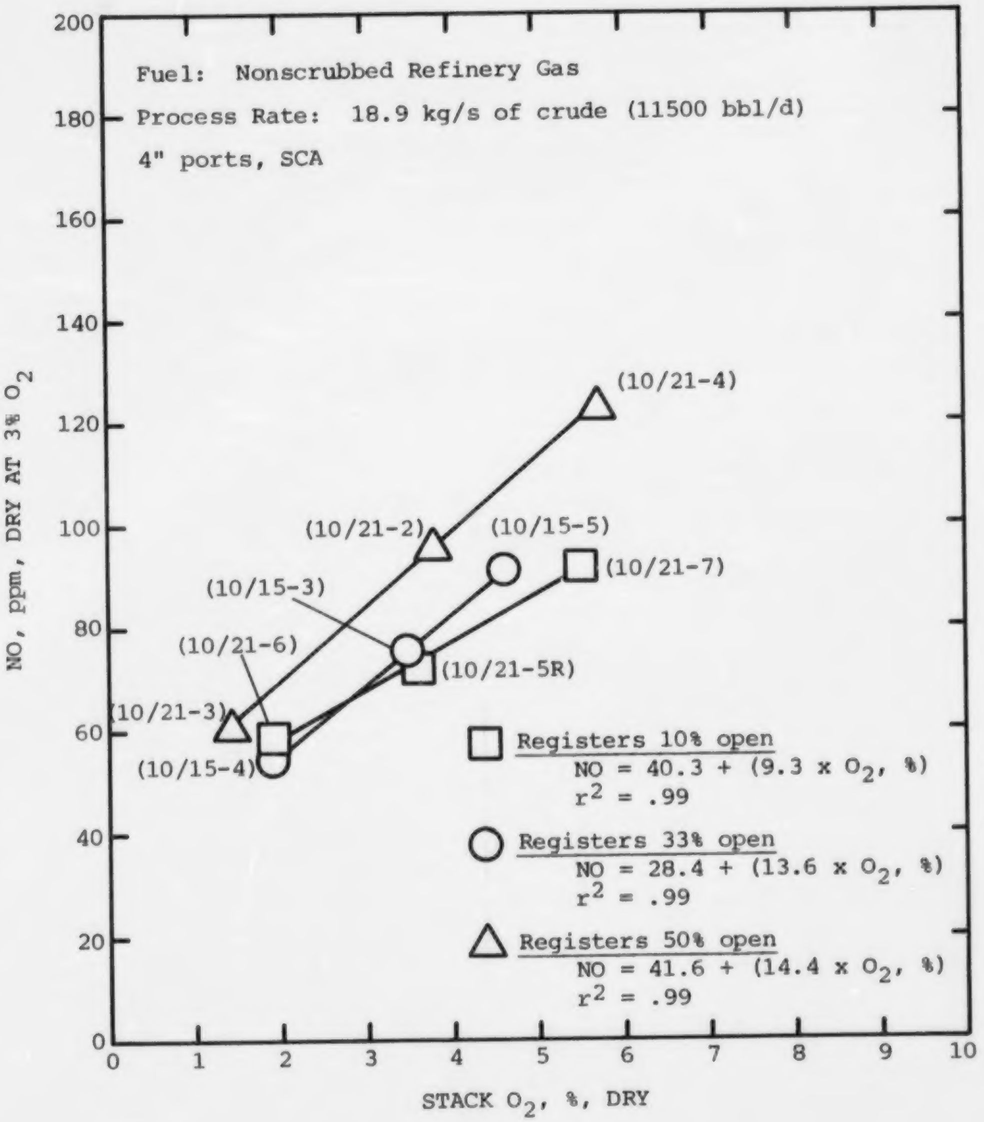

Figure 3-7. NO emissions at three secondary air register settings as a function of stack oxygen for a natural draft process heater with naturally drafted staged combustion air. (18.9 kg/s, 11500 bbl/d process rate)

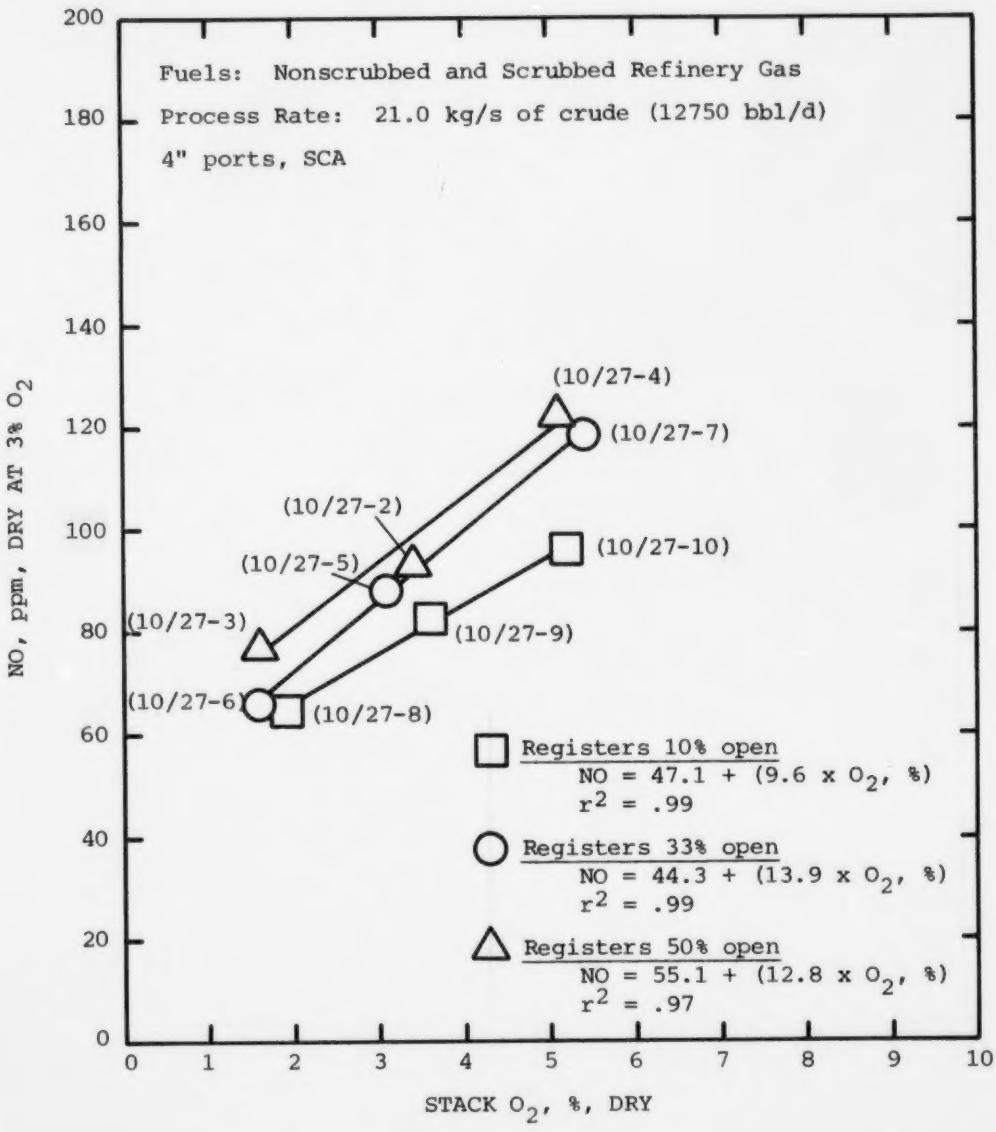

Figure 3-8. NO emissions at three secondary air register settings as a function of stack oxygen for a natural draft process heater with naturally drafted staged air. (21.0 kg/s, 12750 bbl/d process rate)

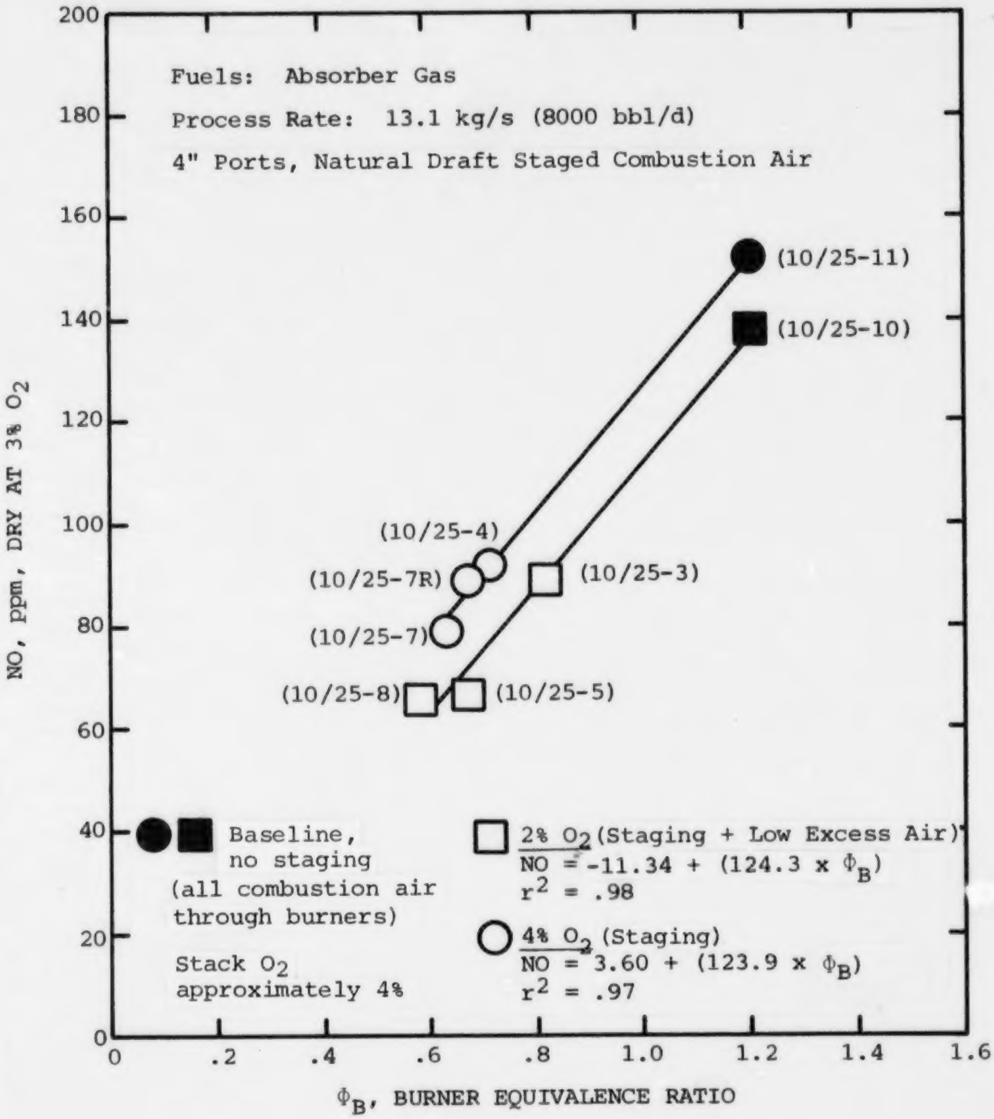

Figure 3-9. NO emissions at two different stack oxygen concentrations as a function of burner equivalence ratio.

52.7 m^3/hr (8000 bbl/day), 55 percent of rated capacity. For each O_2 level (2,4 percent), the burner equivalence ratio was lowered in increments by closing the stack damper and closing down the burner air registers either to 50 percent, 33 percent, or 10 percent open. The minimum burner equivalence ratio for any O_2 level was that associated with the registers 10 percent open. At 4 percent O_2 (SCA only), the minimum Φ_B obtained was 0.63 (48 percent of total air is staged air) which reduced NO emissions 48 percent below the baseline of 152 ppm, dry at 3 percent O_2. At 2.3 percent O_2 (SCA + LEA from a stack O_2 percent of 3.7) the minimum Φ_B obtained was 0.58 (51 percent of total air is staged air) which reduced NO emissions 51 percent below the baseline of 138 ppm, corrected to 3 percent O_2. These percentages staging air are higher than those presented in Table 3-1 because total air requirements are less at this crude charge rate and associated fuel thermal input rate.

Figure 3-10 shows the effect of staging (decreased burner equivalence ratio) on NO emissions. The crude charge rate for this test series was 84.5 m^3/hr (12,750 bbl/day), 90 percent of rated capacity. For each nominal O_2 level (2, 4, 6 percent), the burner equivalence ratio was lowered in increments by closing down the burner air registers either to 50 percent, 33 percent, or 10 percent open with stack damper adjustments. The minimum burner equivalence ratio for any O_2 level was that associated with the registers 10 percent open. At 4 percent O_2 (SCA only), the minimum Φ_B was 0.68 (43 percent of total air is staged air) which reduced NO emissions 43 percent below the baseline of 152 ppm, dry at 3 percent O_2. At 2 percent O_2, (SCA + LEA) the minimum Φ_B obtained was 0.53 (56 percent of total air is staged air) which reduced NO emissions 56 percent below the baseline of 68 ppm, dry at 3 percent O_2.

Percent changes in fuel consumption with NO reduction were calculated to show the extent of fuel savings with staged air combustion modification, lowered excess air, and staged air combined with lowered excess air. Staged combustion air at 4 percent and 2 percent oxygen (no lowered excess air) showed consistent NO reduction rates of 45 to 50 percent. Average fuel savings are on the order of one-half to one percentage point. The fuel savings become more significant (on the order of one to two percentage points) with

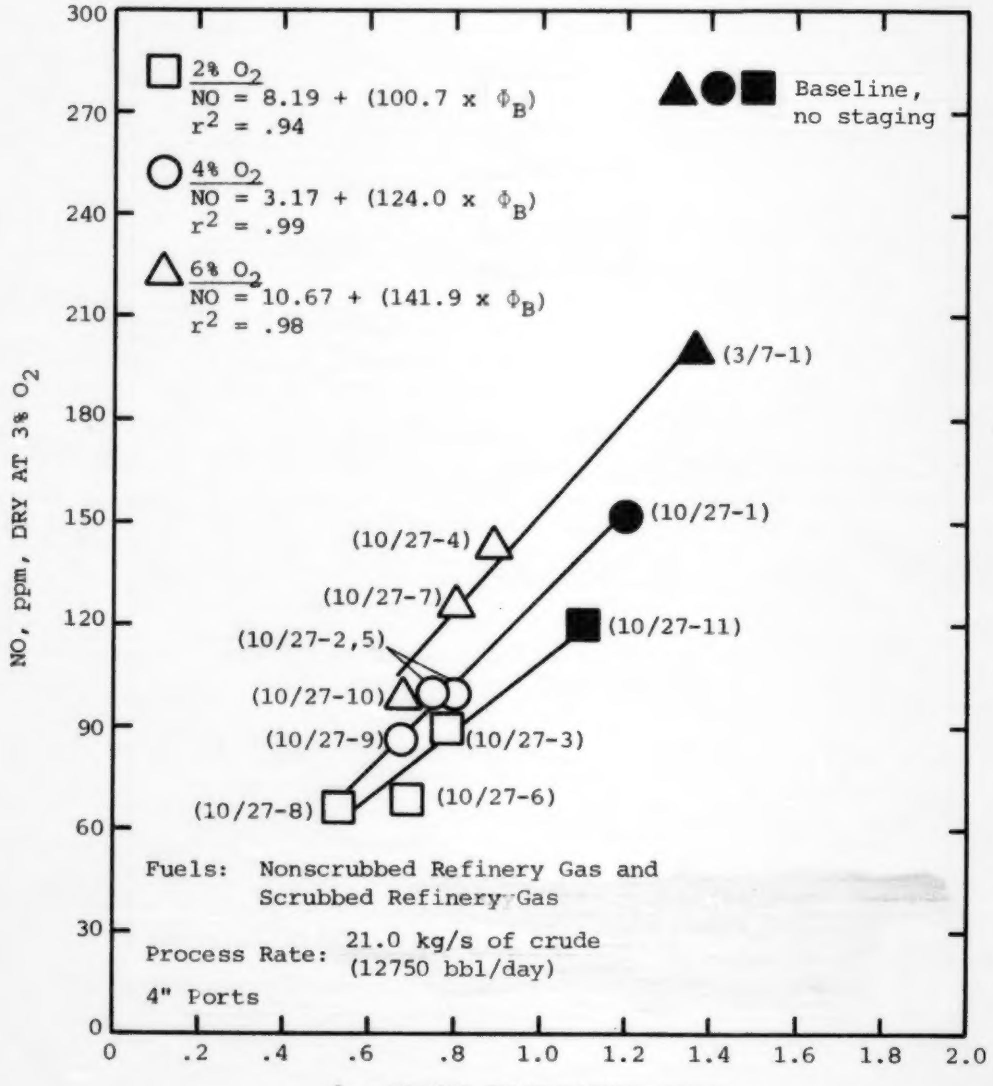

Figure 3-10. NO emissions as a function of burner equivalence ratio at three oxygen levels with 4" ports.

staged air combined with lowered excess air. At the same time, a benefit with NO reduction of approximately 50-55 percent is realized. These maximum NO reductions and fuel savings were typical for the maximum staging achieved by the 4-inch ports.*

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*The percentage change in fuel consumption was calculated as follows:

$$\frac{\eta_{unmod} - \eta_{mod}}{\eta_{mod}} \times 100\%$$

Thus a positive number represents an increase in fuel consumption and a negative number represents a decrease in fuel consumption.

SECTION 4.0

RESULTS OF COMBUSTION MODIFICATION TESTS WITH 80 PERCENT OIL, 20 PERCENT GAS FIRING

The following sections present test data for the crude heater firing on 80-20 oil/gas mixture. Baseline data (without combustion modifications) and modified heater operations data (natural draft and forced draft staged combustion air) are discussed in regards to NO emissions and heater efficiency. A complete data summary of these process heater tests is provided in Appendix B. Gas and oil analyses are presented in Appendix D.

4.1 HEATER PERFORMANCE (NO STAGING)

Prior to making any combustion modifications, two consecutive days of baseline data were collected with the 80 percent fuel oil/20 percent absorber gas firing arrangements. Average baseline conditions for this fuel combination were 144 ng/J NO at 3.7 percent stack oxygen with an ASME efficiency of 76.2 percent. Figure 4-1 shows the mean and standard deviation NO and O_2 concentrations over the duration of the long-term baseline testing. Previous baseline data for a 50/50 mixture of absorber gas/ No. 6 oil mixture show baseline NO levels of 115 ng/J along with a measured ASME efficiency of 76 percent (Ref. 1). A feed rate of about 76 m^3/h (11,500 bbl/day) at approximately 4 percent O_2 in the stack gas defined baseline conditions firing the mixed gas/oil fuel. The secondary air registers were 33 percent open during the baseline conditions. Fuel nitrogen conversion efficiency of the 80-20 oil/gas mixture was comparable to the 50-50 oil/gas mixture. Estimated fuel nitrogen conversion efficiency, based on the oil/gas ratio in the fuel and oil fuel nitrogen content (~0.8%), was approximately 30-35 percent.

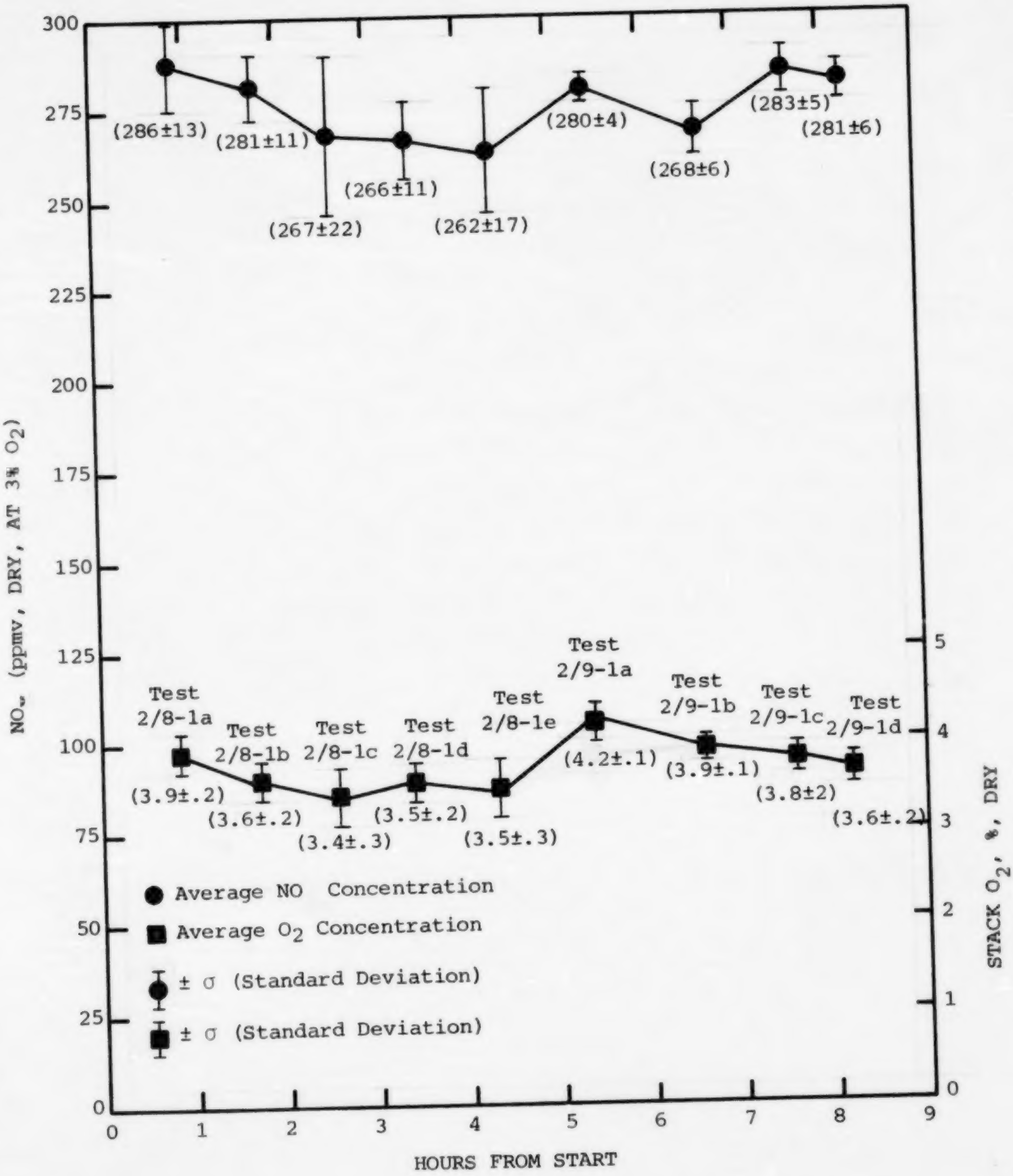

Figure 4-1. Long-term Baseline NO and O_2 Emissions (80% Oil/ 20% Gas Firing)

4.1.1 Load and Excess Air Variations

Three crude charge rates were run for the oil/gas firing mixture with stack O_2 variation. NO emissions and efficiencies were evaluated for the varying load and excess oxygen conditions.

NO emissions as a function of stack oxygen for three crude charge rates are shown in Figure 4-2. At the higher crude charge rates (11,500 and 14,000 bbl/day), the oxygen level could be decreased to approximately 2.5 to 3 percent O_2 before CO and smoking problems occurred. The percent oxygen at low crude charge rate (8,000 bbl/day) was dropped to 2 percent without incident. The lower excess air levels were achievable at the lower crude charge rate since the oil/gas firing was lower (on the order of 75 percent oil/25 percent gas) during the testing day. Linear regression analyses were run for the NO versus O_2 data. The coefficient of determination, r^2, for each crude charge rate was better than 0.96 indicating an excellent linear curve fit to the data.

Statistical analyses were performed on the baseline NO data (80 percent rated capacity) at 4 percent and 6 percent stack O_2. Figure 4-3 shows the linear regression curve drawn for these data points. The coefficient of determination, r^2, is 0.87 indicating a good linear curve fit to the data. The average efficiency at 4 percent stack oxygen was 76.7 percent and at 6 percent stack oxygen was 75.5 percent.

The 95 percent confidence interval for the 4 percent O_2 data is 13.24 ppm and 8.5 ppm for the 6 percent O_2 data. These deviations from the mean are attributable to one or more factors. One of the reasons for the wide range of baselines is the change in fuel split from day to day. The nominal fuel split for the testing was 80 percent oil/20 percent gas firing on a fuel thermal input basis. During the testing, the fuel splits by percentage of total fuel heat input ranged from 85 percent oil/15 percent gas to 75 percent oil/25 percent gas. Changes in fuel split occurred during fuel switches (e.g., from a scrubbed refinery gas to a nonscrubbed refinery gas with Southern California gas and/or propane) which could affect the fuel gas thermal input value. Further changes in baseline numbers will be reflected by changes in the crude in temperature, which alters the fuel input to maintain constant crude outlet temperature.

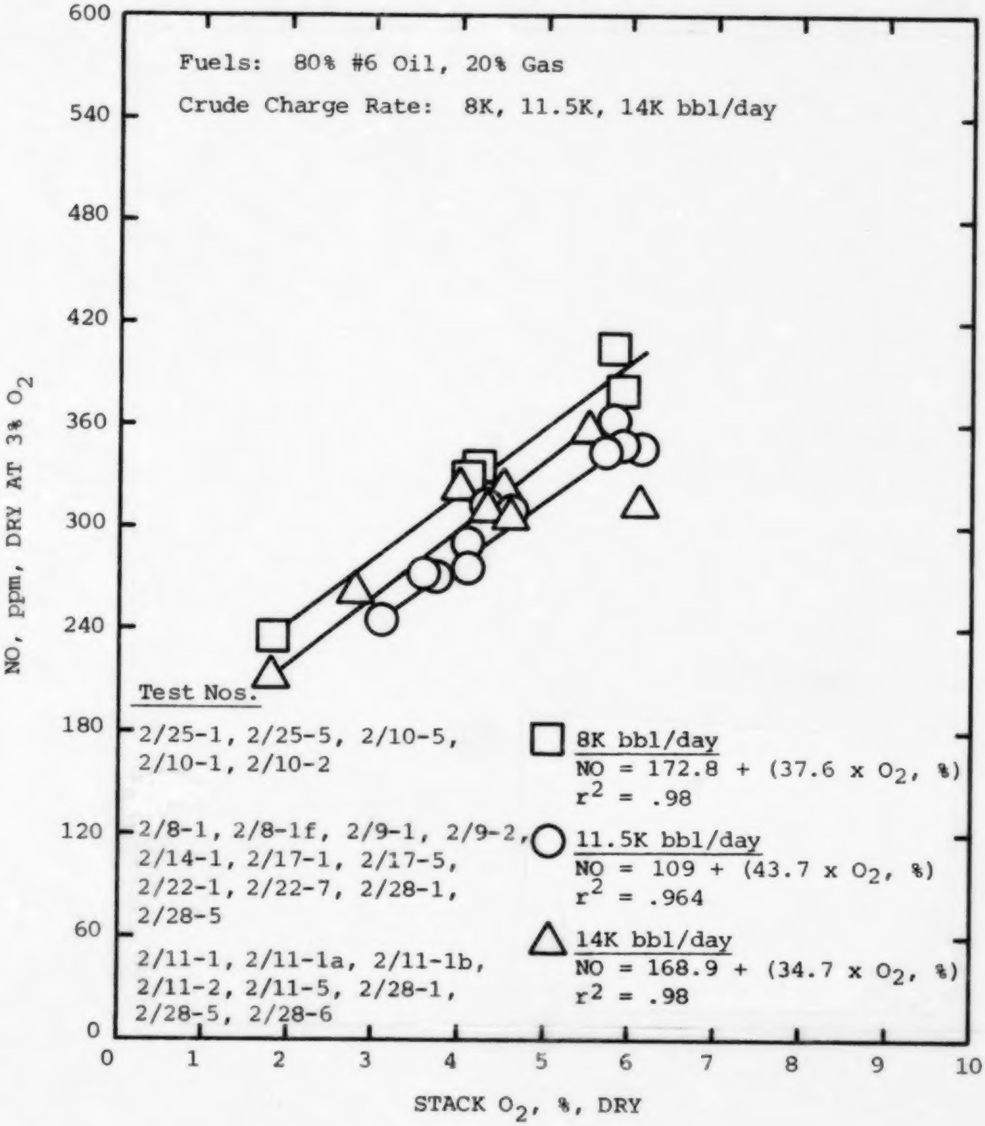

Figure 4-2. Baseline NO emissions at three crude charge rates as a function of stack oxygen.

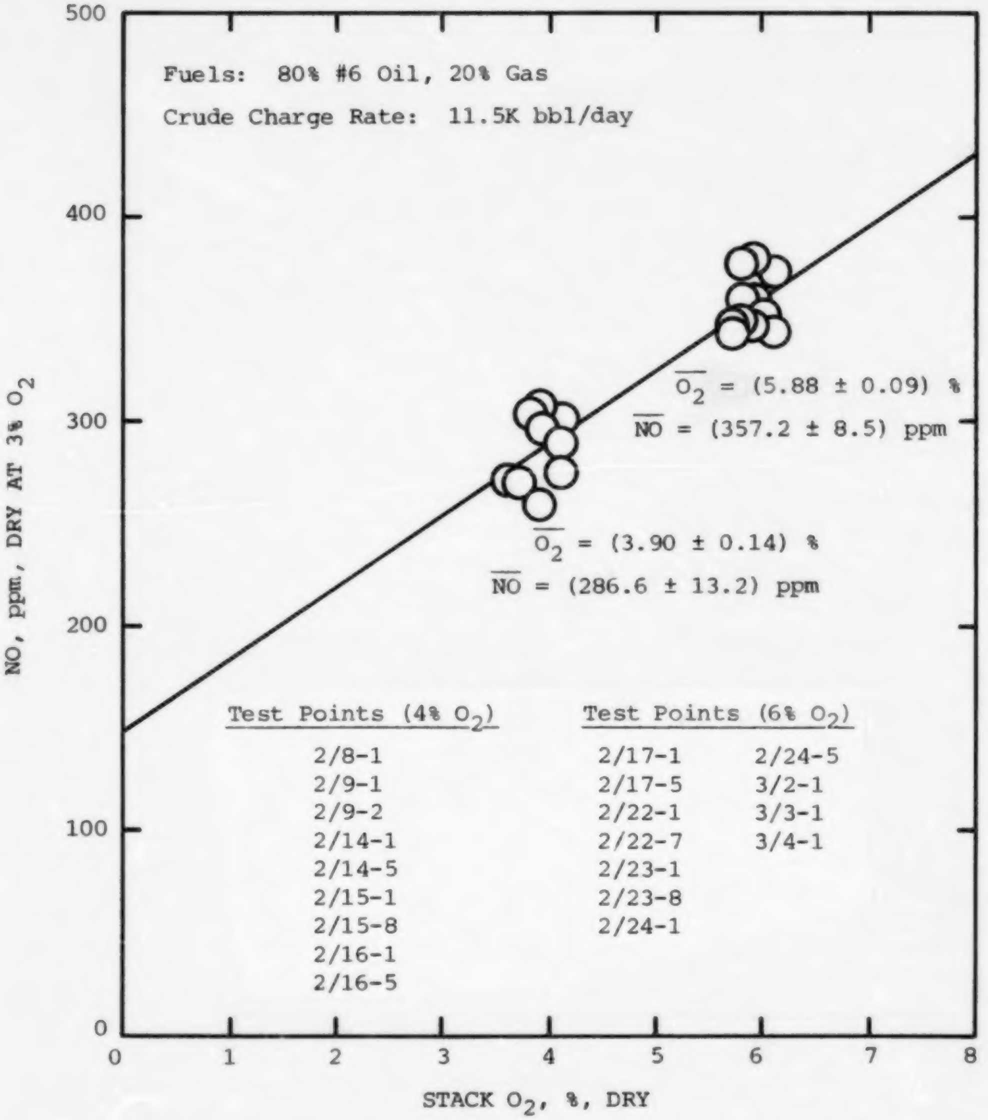

Figure 4-3. Baseline NO emissions at two stack oxygen concentrations.

4.2 HEATER PERFORMANCE (FORCED DRAFT STAGING)

Tests were initially conducted with the forced draft staged combustion air system to assess the levels of NO reduction attainable at various staging heights and burner equivalence ratios. Only 1-1/4-inch lances were tested with the forced draft system. The optimum stage height for NO reduction was determined from this series of tests and then used for the duration of the test sequence. Figure 4-4 shows the NO emissions as a function of burner equivalence ratio for four different staging heights: 0.6 m (2 ft), 0.9 m (3 ft), 1.2 m (4 ft), and 2.5 m (8 ft). For all of these tests, the crude charge rate was kept constant at 76 m^3/h (11,500 bbl/day) 80 percent of rated capacity and the fuel gas burned was scrubbed refinery gas (absorber gas). The staging height is the height above the furnace floor at which the staged combustion air is injected. The burner equivalence ratio for the 8-ft staging height could not be reduced as much as those at the three other staging heights. This was due in part to a lower crude in temperature at the time (325-330°F as opposed to 350°F) which required a higher fuel input rate to maintain crude outlet temperature consistency. The maximum staged air flow achieved by the blower was sufficient to lower the burner equivalence ratio only slightly below stoichiometric.

The 4-ft staging height was chosen as the optimum stage height. Although the percent reduction as a function of burner equivalence ratio was more appreciable at the 8-ft height (down to burner equivalence ratios of 1.0), the stack oxygen could not be kept at a constant oxygen level (4 percent O_2) while operating at minimum burner equivalence ratio (maximum staging). The operating oxygen concentration for maximum staging (8-ft staging height) was 5.2 percent. A fraction of the staging air injected through the 8-ft lances was not interacting in the combustion process. The oxygen was not being consumed in the furnace staging height, thus increasing the stack oxygen concentration. The 4-ft staging height was the optimum for achieving absolute NO emissions reduction, maintaining an O_2 of 4 percent at minimum burner equivalence ratio.

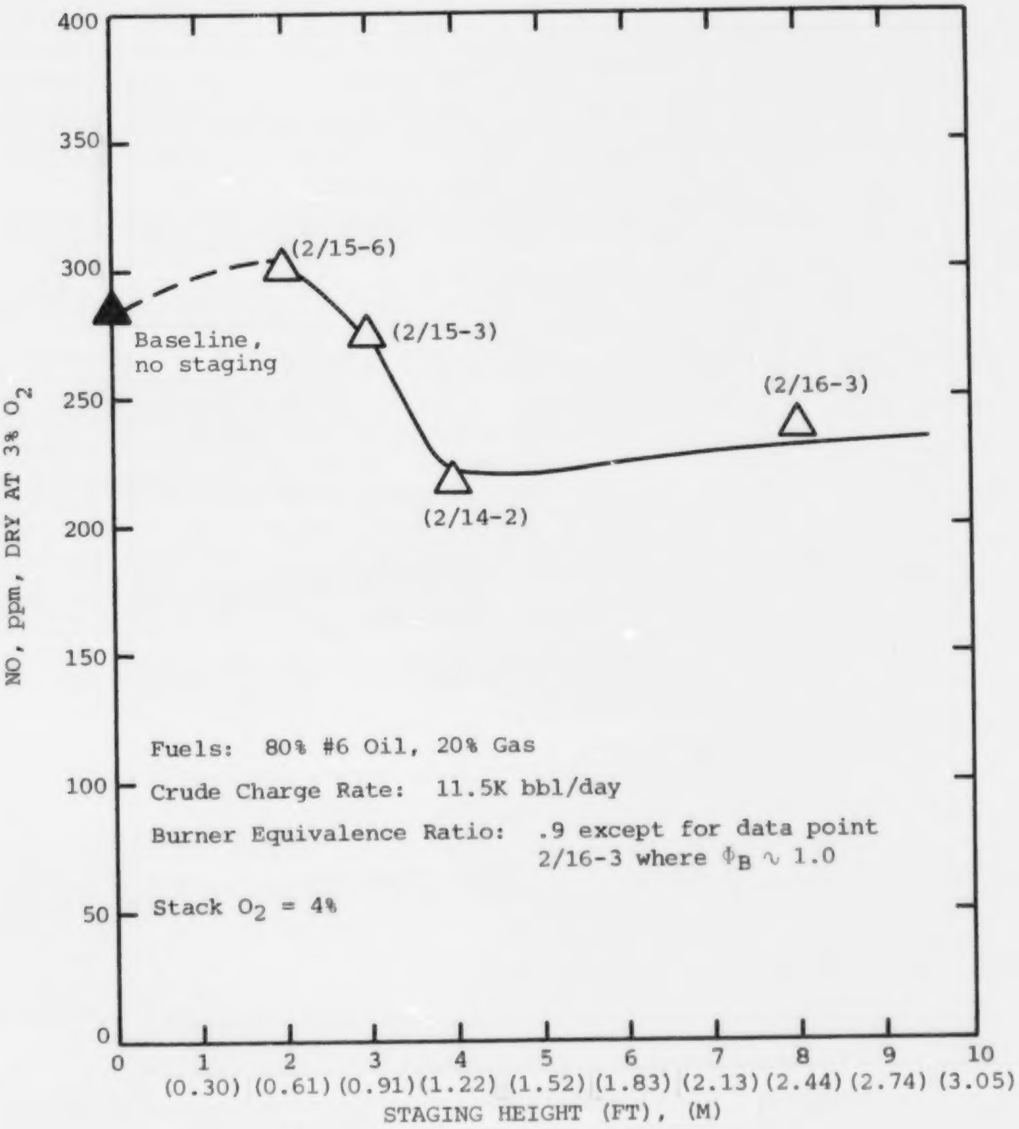

Figure 4-4. NO emissions as a function of staging height at constant stack oxygen and burner equivalence ratio.

A test series was also run at the 4-ft staging height to compare results with the lance tips oriented toward the heater centerline and with lance tips oriented toward the centerline of each burner. The staging air injected by lance tips oriented toward the burner centerline provided better combustion (quantitatively noted by CO emissions and qualitatively determined by furnace inspection and stack watch), but approximately 5 percent points less in NO reduction than the tips oriented to the heater centerline. Smoking problems were incurred lowering the stack oxygen below 4 percent with the lance tips toward the heater centerline. No CO or smoking problems occurred with stack oxygen levels ranging from 2.6-4.3 percent when the lance tips were oriented toward the burner centerline. From an operational standpoint, the lance tips oriented toward the burner centerline were the best arrangement for minimal flame impingement, CO and smoke problems while providing a significant reduction in NO emissions.

Figure 4-5 shows NO emissions as a function of burner equivalence ratio for two oxygen levels. The staging height for these tests was 1.2 m (4 ft) and the crude charge rate was 76 m^3/h (11,500 bbl/day). The burner equivalence ratio was decreased in increments to its minimum value determined by limitations of the staged air combustion fan. At 6 percent O_2, the minimum Φ_B (maximum staging) obtained was 0.97 which decreased NO emissions 18 percent below the baseline of 345 ppm NO, dry at 3 percent stack oxygen level. At 4 percent O_2, the minimum Φ_B (maximum staging) obtained was 0.71 which decreased NO emissions 24 percent below the baseline of 265 ppm NO, dry at 3 percent stack oxygen. Approximately, 40 percent of the total combustion air was injected through the 24 1-1/4-inch lances for the 4 percent stack O_2 test series while 29 percent of the total combustion air was injected through the lances for the 6 percent stack O_2 test series. The lower percent staged air for the 6 percent stack O_2 test series is due in part to the higher fuel heat input rate that day (2/17). A linear regression analysis for both oxygen levels showed an excellent correlation (r^2 better than 0.94) between NO and burner equivalence ratio.

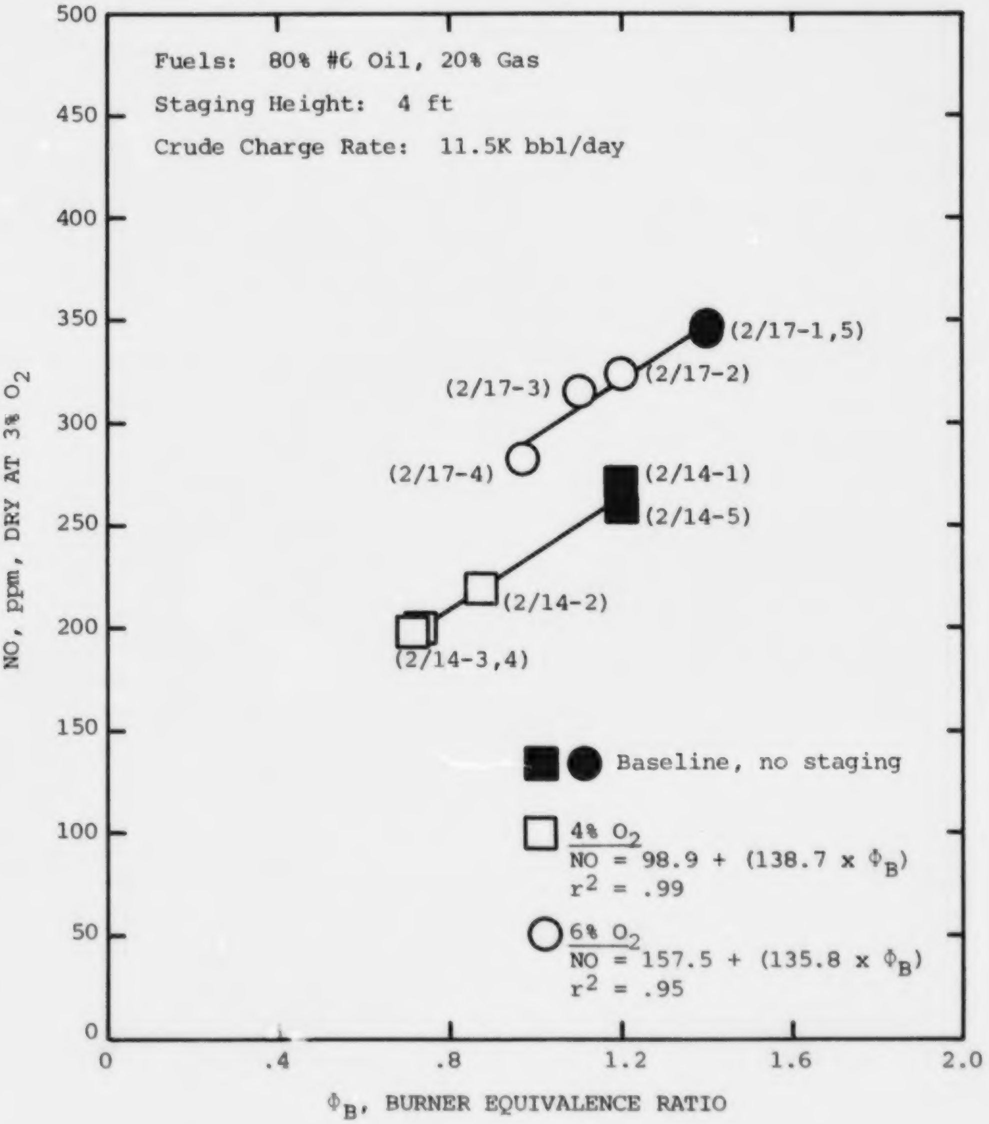

Figure 4-5. NO emissions as a function of burner equivalence ratio for two stack oxygen concentrations.

The extent of NO reduction with burner equivalence ratio for constant O_2 is shown in Figure 4-6. The stack O_2 was maintained at approximately 6 percent O_2. Staged combustion air lowered the burner equivalence ratio from 1.37 to 0.66 and reduced NO emissions 30 percent from a baseline of 404 ppm at 3 percent O_2. The efficiency increase for the staged air combustion modification was 3.9 percent resulting in a fuel savings of 3.7 percent.

4.3 HEATER PERFORMANCE (NATURAL DRAFT STAGING)

A series of tests at 8,000 bbl/day crude charge rate and 14,000 bbl/day crude charge rate were run to investigate the impact of natural draft staged combustion air (SCA) and staged combustion air with low excess air (SCA + LEA). Staged combustion (4" ports) for a constant stack oxygen level (4 percent O_2) decreased NO emissions by approximately 30 percent from the baseline for both crude charge rates without CO or smoking problems. The combination of staged combustion air using 4" ports with low excess air was effective in lowering the stack oxygen level between 2.0-2.5 percent, providing NO reduction of approximately 60 percent from the baseline. For the 8,000 bbl/day crude charge rate, the baseline of 178 ng/J NO was reduced 68 percent by using staging and lowered excess air. The stack O_2 was decreased from 4.1 to 2.2 percent. For the 14,000 bbl/day crude charge rate, the baseline of 180 ng/J NO was reduced 58 percent by using staging and lowered excess air. The stack O_2 was decreased from 4.0 to 2.0 percent. Although NO reduction was good, flame quality was poor and average CO emissions were quite high (approximately 40 ppm at 3 percent O_2). The low NO operating condition was unacceptable because of the CO and smoke problems.

Figure 4-7 compares the effectiveness of natural draft staged air with forced draft staged air for NO reduction only. In this instance, the process rate was maintained at approximately 14,000 bbl/day and the stack oxygen maintained at 4 percent for baseline and staging conditions. The results show that for maximum staging (minimum burner equivalence ratio), the 4" ports (NDSCA) and 1-1/4" lances (FDSCA) provide very comparable NO reduction for approximately the same amount of staging. It should be noted that the 1-1/4"

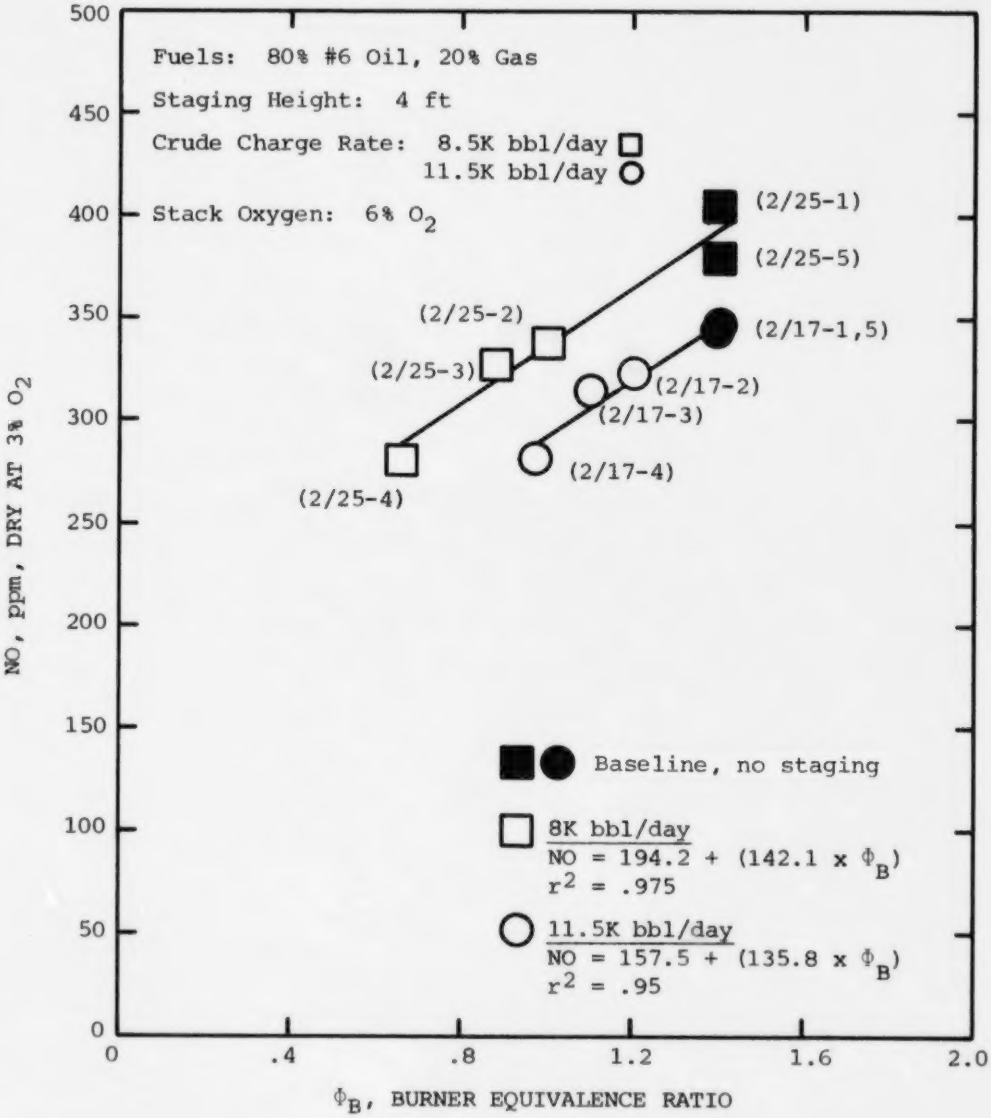

Figure 4-6. NO emissions as a function of burner equivalence ratio for two process rates at constant O_2.

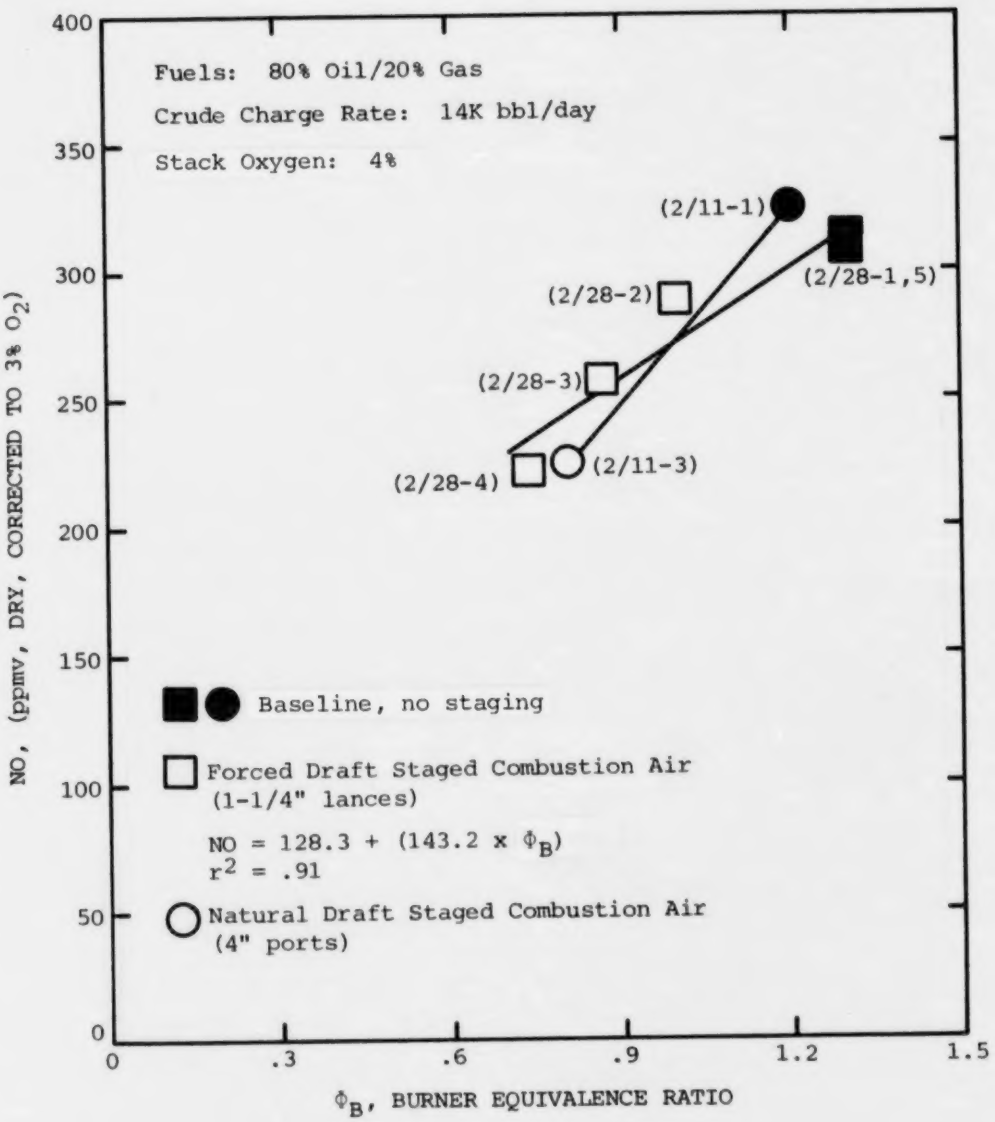

Figure 4-7. NO emissions as a function of burner equivalence ratio for natural draft staged air and forced draft staged air.

lances of the forced draft system provided better mixing of the air and fuel resulting in lower amounts of smoke and CO compared with the 4" ports of the natural draft system.

4.4 HEATER PERFORMANCE (PARTICULATES, SO_2/SO_3, N_2O)

Particulates, SO_2/SO_3 and N_2O were measured under both baseline and staging conditions with combination oil/gas firing. Baseline particulates and SO_2/SO_3 were determined under normal operating conditions while the staging tests were conducted under abnormal operating conditions (i.e., a heavily sooted convection section). This unusual operating condition rendered impossible similar fuel firing conditions as at baseline. Repeat baseline tests were not run at this operating condition due to time constraints. Interpretation of these results must be tempered by this awareness of changes in heater operation.

4.4.1 Particulate Measurement

Baseline particulate tests (test numbers 3/2-1 and 3/3-1) were conducted at a process rate of 75.9 m^3/h (11450 bbl/day), fuel firing ratio of 22 percent gas/78 percent oil and an average stack O_2 of 5.8 percent. The average particulate emission rate based on two Method Five tests was 42.9 nanograms per joule (.10 pounds per million Btu). Later in the test program, particulates were sampled with the forced draft staged air system in operation (test numbers 6/9-2 and 6/9-3). The operating conditions had unavoidably changed, as discussed earlier, such that the oil/gas fuel firing ratio was now 36 percent gas, 64 percent oil. Average particulate emissions were 52.8 nanograms/joule (.123 pounds per million Btu) for a process rate of 77.1 m^3/h (11630 bbl/day), fuel firing ratio of 36 percent gas/64 percent oil and an average stack O_2 of 2.1 percent. The sooted state of the convection section is responsible, in part, to the heavier particulate load at the staged air operating condition.

4.4.2 N_2O Measurement

Stack gas samples for N_2O analysis were collected under similar operating conditions for both baseline and staging conditions. The baseline test

(#6/8-1) consisted of a process rate of 77.1 m^3/h (11630 bbl/day) and fuel firing ratio of 29 percent gas, 71 percent oil. The average N_2O concentration of 53 ppmv, uncorrected, was determined by chromatographic measurement. An N_2O/O_2 ratio of 63 ppmv/3.11 percent was measured for one of the samples.

At the modified condition of 31 percent gas, 69 percent oil firing and a process rate of 77.1 m^3/hour, an average N_2O concentration of 70 ppm from three samples was determined using chromatographic measurement. An N_2O/O_2 ratio of 60 ppmv/4.76 percent was measured for one of the samples.

4.4.3 SO_2/SO_3 Measurement

Two Goksoyr Ross tests (Nos. 3/4-1 and 3/4-2) were run consecutively at both baseline and staging conditions. The baseline condition consisted of a 77.1 m^3/h (11630 bbl/day) process rate, fuel firing ratio of 17 percent gas, 83 percent oil and stack oxygen of 5.8 percent. The SO_2 concentration as determined by the Goksoyr Ross technique averaged 423 ppm at 3 percent O_2, dry and the SO_3 concentration averaged 3.5 ppm at 3 percent O_2, dry.

At the modified operating condition (forced draft staged combustion air), the refinery heater process rate was 75.9 m^3/hr (11450 bbl/day), fuel firing ratio was set at 37 percent gas, 63 percent oil firing and the stack oxygen averaged 2.3 percent. The reason for the lower amount of oil firing during the staging test was the heavily sooted convective section. The SO_2 concentration as determined by the Goksoyr Ross technique averaged 182 ppm at 3 percent O_2, dry and the SO_3 concentration averaged 1.8 ppm at 3 percent O_2, dry.

SECTION 5.0

RESULTS OF LONG-TERM TESTS UNDER BASELINE AND NATURAL DRAFT STAGED COMBUSTION AIR CONDITIONS

This section presents the results of a long-term (15-day) continuous monitor test to evaluate the long-term gaseous emissions from a gas-fired petroleum crude heater modified for natual draft staged combustion air. Gaseous emissions data were gathered continuously from the crude heater operating at approximately 82 percent of rated capacity. Gaseous emissions data included NO, O_2, CO_2, and CO. The results of the 15-day test along with baseline tests (no staging) are discussed in the following sections.

5.1 TABULATION OF RESULTS

An on-line Emissions Monitor Program was written for the Apple II Plus 48K computer to provide automatic digital data acquisition for real time monitoring of emissions data. The data logger was programmed to scan every 6 seconds and print 15-minute averages. The program provides a continuous visual display including time plots of selected data and records the one-minute averages and 15-minute averages on a magnetic disk. Strip chart recorders are used to verify the data recorded on magnetic disk and fill in any gaps from the data logger, should they occur. Heater operating data (temperatures, flows, pressures) were tabulated on a daily basis to supplement the gaseous emissions data gathered. Any changes in the gaseous emissions data were traced to fuel changes, crude change rate changes, crude inlet temperature changes, etc.

A complete listing of the 15-minute averages is shown in Appendix C and the 24-hour averages is shown in Table 5-1. The 24-hour averages were calculated for the entire test period based on the 15-minute averages.

Two days of baseline data (no staging) were gathered prior to the start of the long-term test with one additional day of baseline data gathered at the completion of the 15-day test. Table 5-2 shows the mean and standard

TABLE 5-1. PETROLEUM PROCESS HEATER, STAGED COMBUSTION AIR 24-HOUR DATA

Dry Stack Gas Concentration
Crude Charge Rate: 11,456 bbl/day

Day No.	O_2 Vol % Meas.	CO_2 Vol % Meas.	CO ppmv Meas.	NO ppmv 3% O_2	CO (ng/J)	NO (ng/J)
1	4.5	10.7	15	79	5	40
2	3.3	11.3	9	71	3	36
3	3.9	10.4	16	102	5	52
4	3.4	10.7	30	68	10	35
5	3.1	11.1	30	86	9	44
6	3.9	11.0	10	93	3	47
7	2.9	10.8	5	58	2	30
8	2.5	11.4	24	97	7	50
9	2.6	10.9	40	112	13	57
10	4.7	10.2	32	106	11	54
11	3.9	10.5	41	106	13	54
12	2.7	11.0	28	84	9	43
13	3.0	11.8	19	91	6	46
14	3.2	10.8	9	96	3	49
15	4.3	--	5	102	2	52

Note: Day Nos. 1-9: Nonscrubbed refinery gas and/or natural gas with propane-propylene makeup.

Day Nos. 10-15: Scrubbed refinery gas.

NO on a mass basis is in terms of NO_2.

TABLE 5-2. BASELINE DATA SUMMARY

Time Interval From Start (hrs)	$\overline{O}_2$, %, dry	σ_{O_2}	$\overline{NO}$ (ppmv, dry at 3% O_2)	σ_{NO}	Fuel Source
0-3	3.7	0.6	118.5	38.3	Fuel Gas Drum, Nat. Gas
3-6	4.2	0.1	153.3	1.7	Fuel Gas Drum Only
6-9	4.5	0.2	152.1	4.6	
9-12	5.0	0.2	157.1	1.5	
12-15	5.2	0.1	157.4	2.7	
15-18	5.4	0.1	154.8	1.6	
18-21	5.5	0.1	152.1	1.7	
21-24	4.9	--	147.0	--	
24-27	3.9	0.7	139.1	10.9	Fuel Gas Drum, Nat. Gas
27-30	3.7	1.0	77.9	14.8	
30-33	4.5	0.2	86.9	14.5	
33-36	4.6	--	73.5	--	
36-39	4.6	0.4	97.1	19.9	
39-42	4.6	0.2	114.6	11.8	
42-45	4.7	0.1	116.1	24.1	
45-48	4.3	0.3	133.6	36.8	
48-51	3.7	0.4	109.6	6.3	Absorber Gas
51-54	3.1	1.2	112.9	11.0	
54-57	2.8	1.0	111.7	8.7	
57-60	4.1	0.2	121.3	1.2	
60-63	4.4	0.1	120.3	0.5	
63-66	4.6	0.4	119.9	3.1	
66-69	3.7	1.3	107.3	17.4	
69-72	2.9	0.1	104.0	2.4	

deviation for O_2 and NO on a three-hour basis for the baseline testing. During the second 24 hours of baseline testing, the fuel gas components would fluctuate radically at times. Various portions of nonscrubbed refinery gas and/or natural gas were burned in the crude heater (see Section 2.3). If significant amounts of low Btu natural gas were burned, then a propane-propylene mixture was added to the refinery gas to raise the fuel thermal input level. For small variations in oxygen (standard deviation less than 0.5 percent), NO deviation from the mean was ±12-37 ppm (Table 5-2). This large deviation from the mean during the second 24 hours of baseline represented the considerable composition variation of the gas fuel burned in the heater.

Figures 5-1 and 5-2 show the O_2 and NO variation with hours from baseline start, respectively. Figure 5-3 shows NO as a function of stack oxygen and fuel firing prior to and after the 15-day test. For the first two days of baseline testing, NO ranged from 70 ppm (nonscrubbed refinery and Southern California gas) to 160 ppm (nonscrubbed refinery gas only) for constant stack oxygen. The average NO emissions were 127 ppm (corrected to 3 percent oxygen) with a standard deviation of 29.7 ppm. This variability in NO concentration was considerably less during the last 24 hours of baseline. The average NO emissions were 113 ppm (corrected to 3 percent oxygen), with a standard deviation of 6.3 ppm. The lower emissions variability is due to far less variability in the fuel being burned in the heater (absorber gas only). Stack damper and register adjustments were made during the test to provide an NO versus O_2 curve at this baseline condition.

Following the two-day baseline testing, 24 three-inch I.D. lances were positioned at a staging height of approximately four feet inside the crude heater. These lances (four per burner) provided about 30 percent of the total combustion air for the long-term test on a staging air basis only. The stack oxygen percentage was varied during the test by both intentional and unintentional means. Since there are no automatic stack damper and air register controls on the heater, KVB personnel would intentionally lower the stack oxygen to approximately 2 percent with the concurrence of refinery operating personnel. This lowering of O_2 was achieved with a combination of stack

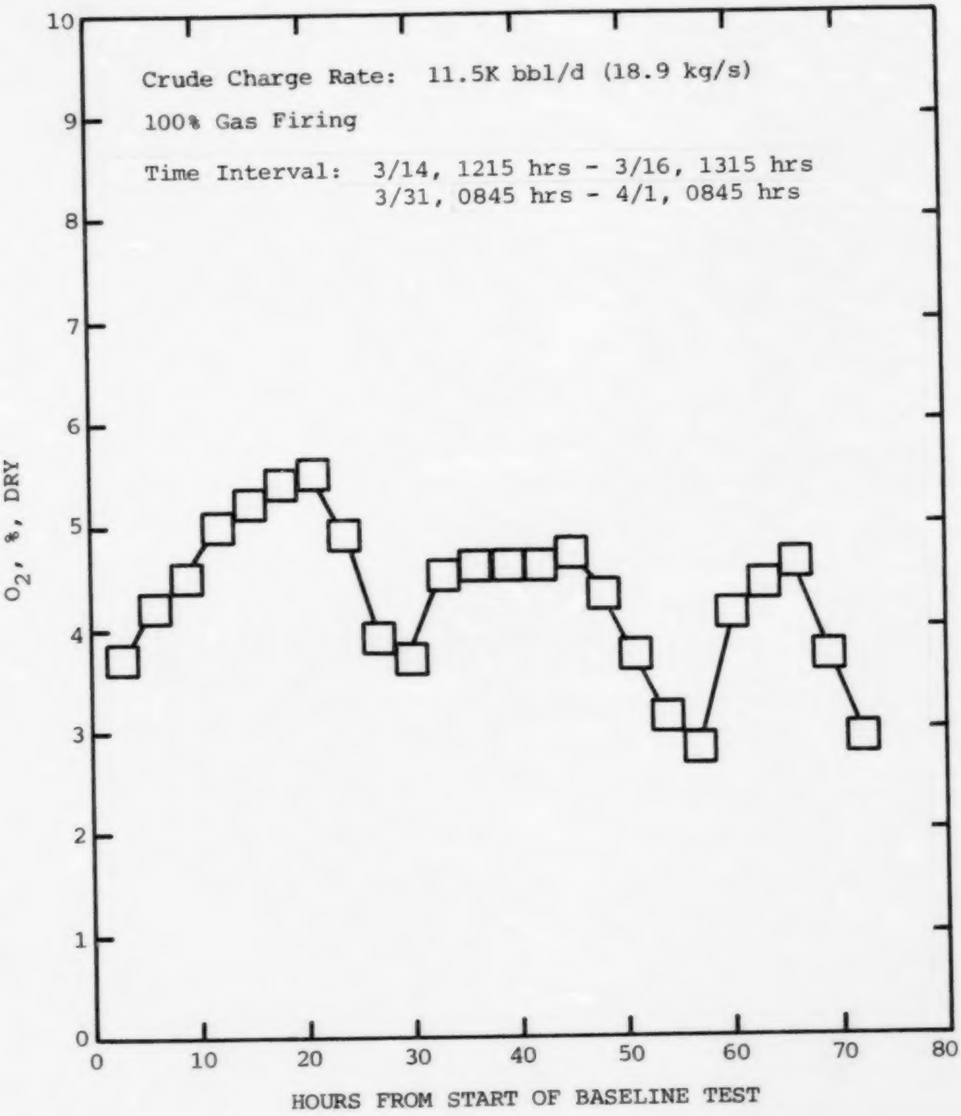

Figure 5-1. Stack Oxygen as a Function of Time for Baseline Tests

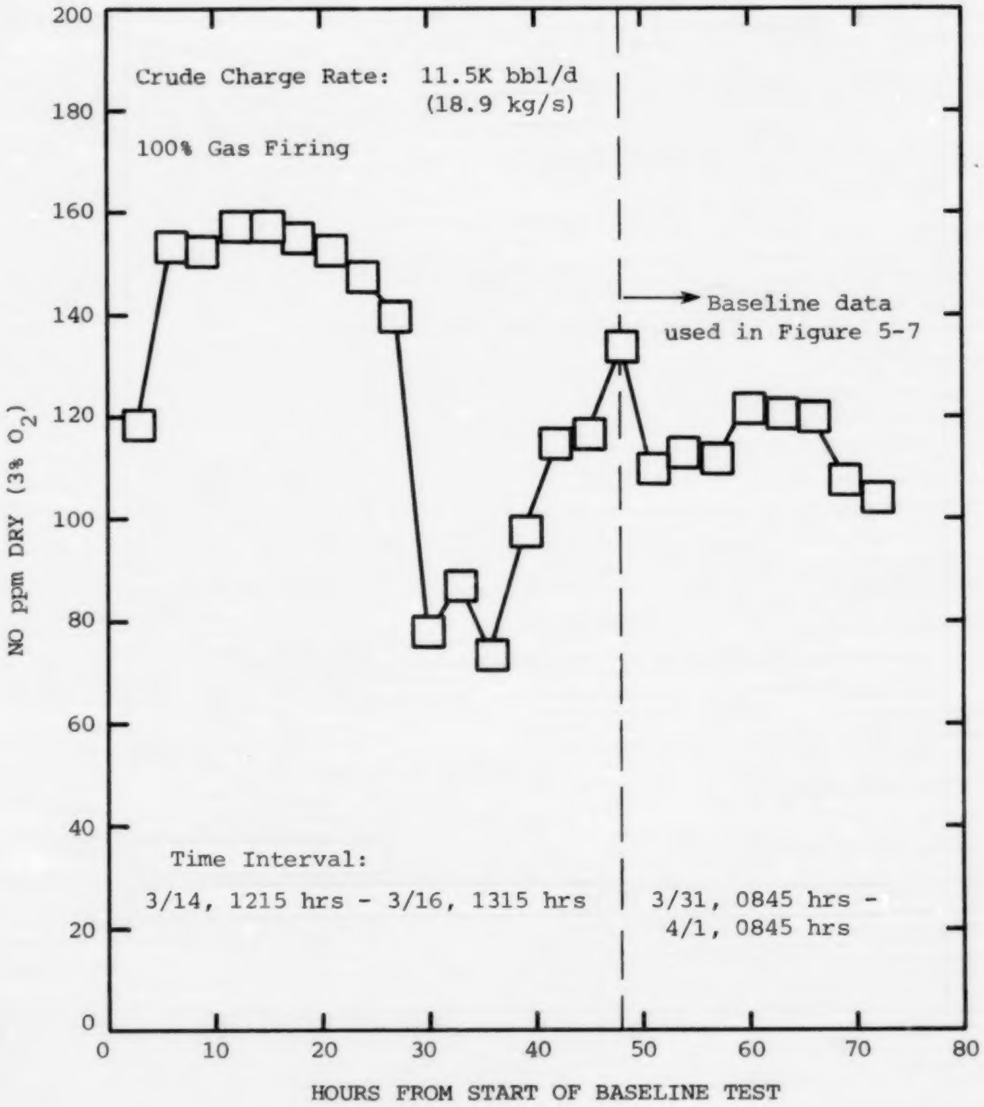

Figure 5-2. NO as a Function of Time for Baseline Tests

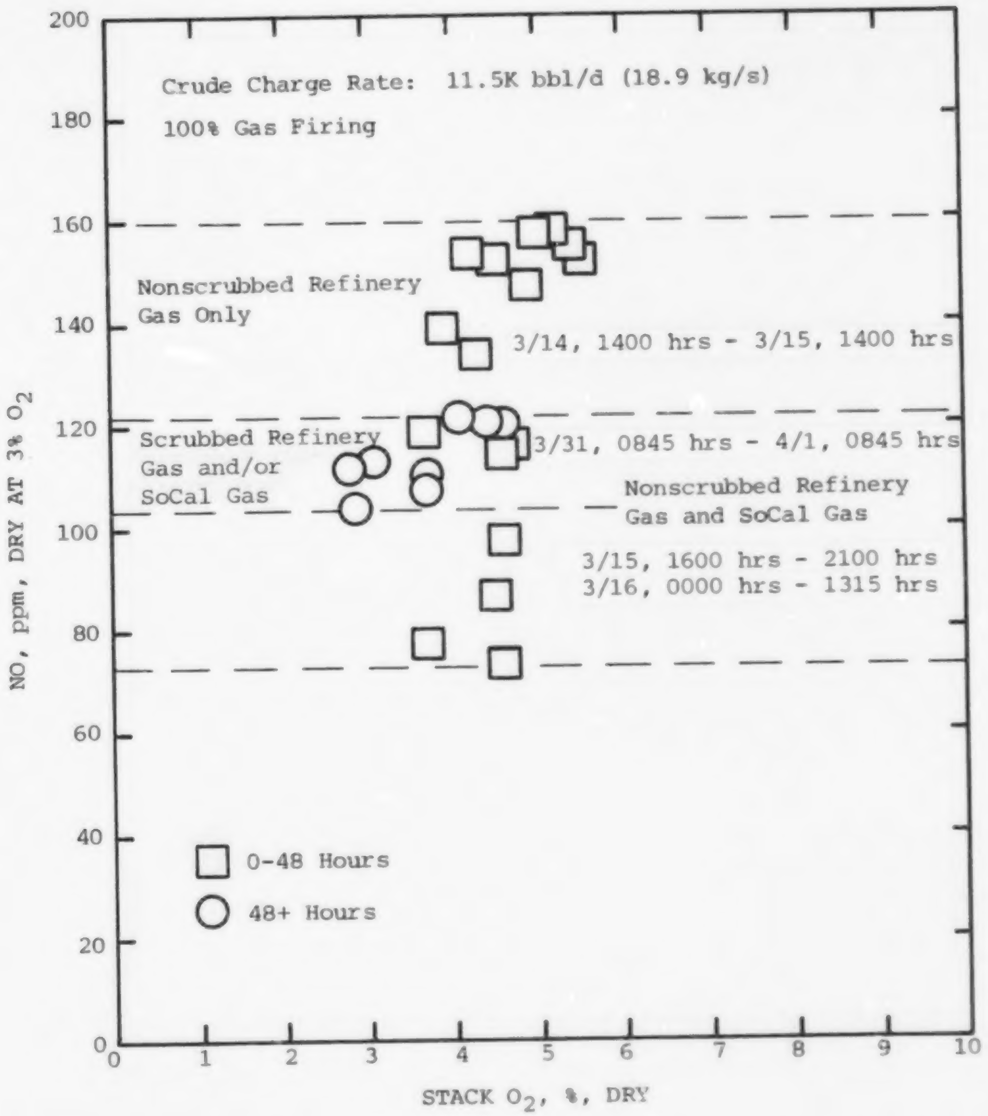

Figure 5-3. NO as a Function of Stack Oxygen for Baseline Tests

damper and/or secondary air register adjustments. The O_2 change was made by KVB personnel when the fuel flow and fuel composition to the crude heater was fairly constant. When KVB personnel were not at the refinery, the stack oxygen was typically set at 4 percent. During the first nine days of the long-term test, the stack oxygen set intentionally at 4 percent would fluctuate unintentionally with variable fuel flow and fuel composition changes. Various portions of nonscrubbed refinery gas and/or natural gas with propane-propylene makeup were burned in the crude heater for these first nine days. The variability of fuel flow and fuel composition was much greater for those first nine days than the last five and one-half days of the long-term test. Scrubbed refinery gas (absorber gas) was burned in the crude heater during those latter test days. The 15-minute averages beginning March 25, 1800 hours, show much less "unintentionally aided" variability of the gaseous emissions data. Table 5-3 lists the ultimate analyses for fuels burned in the heater during the baseline and long-term tests.

The flue gas 24-hour average CO concentration is shown in Figure 5-4 for the test period. As can be seen from the figure, the average daily CO concentration is less than 50 ppm dry, corrected to 3 percent O_2. Some 15-minute CO averages did exceed 1000 ppm due to increased fuel flows. Both O_2 and CO_2 were measured to provide redundant measurements for dilution calculations. Figure 5-5 shows CO_2 and O_2 concentration on a daily average basis for the entire 15-day test period.

The average daily NO concentration (ppm, dry, corrected to 3 percent O_2) with O_2 is presented in Figure 5-6. The fluctuations in the daily NO concentrations can be traced to the fuel flow changes and fuel composition changes along with O_2 trim by stack damper and air register adjustments. These fluctuations were not as severe during the last five days of the long-term test.

Figure 5-7 shows the baseline and staging data of NO versus stack O_2. Linear regression analyses were run for both the baseline data points and staged air data points. The linear regression analysis shows a very good correlation for the staged air data (coefficient of determination, $r^2 = 0.9$) while the coefficient of determination is fairly good for the baseline data

TABLE 5-3. SUMMARY OF GAS ANALYSES FOR BASELINE AND LONG-TERM TEST

	#1 Fuel Gas Drum		So. Cal Gas	Absorber Gas	
	Average % vol	Std. Deviation % vol		Average % vol	Std. Deviation % vol
Hydrogen	8.3	3.7		15.3	2.1
Nitrogen	2.1	0.4	0.8	1.3	0.4
Oxygen	0	0		0	0
Carbon Monoxide	1.3	0.3		1.0	0.1
Carbon Dioxide	2.2	0.6	1.0	0.3	0
Hydrogen Sulfide	0.4	0.2		0	0
Methane	47.9	2.3	90.7	45.1	3.9
Ethane	13.5	1.1	6.1	16.7	0.1
Ethylene	6.5	0.8		7.7	0.4
Propane	4.5	0.8	0.8	4.9	0.2
Propylene	4.1	0.9		5.4	0.6
Isobutane	1.1	0.2	0.1	0.4	0.1
Normal Butane	2.0	0.3	0.1	0.5	0.1
Total Butenes	2.8	0.5		0.9	0.2
1,3 Butadiene	0.3	0		0	0
Isopentane	0.5	0.2		0.2	0
Normal Pentane	0.4	0.1		0.2	0.1
Pentenes	0.5	0		0.1	0
Total C_6 Plus	2.1	0.3	0.2	0.5	0.1
kJ/m^3	52013	1639	39681	47356	484
Btu/ft^3	1396	44	1065	1271	13
F(dscm of Combustion Gas/KJ)	2.311×10^{-4}	0.007×10^{-4}	2.319×10^{-4}	2.290×10^{-10}	0.005×10^{-4}

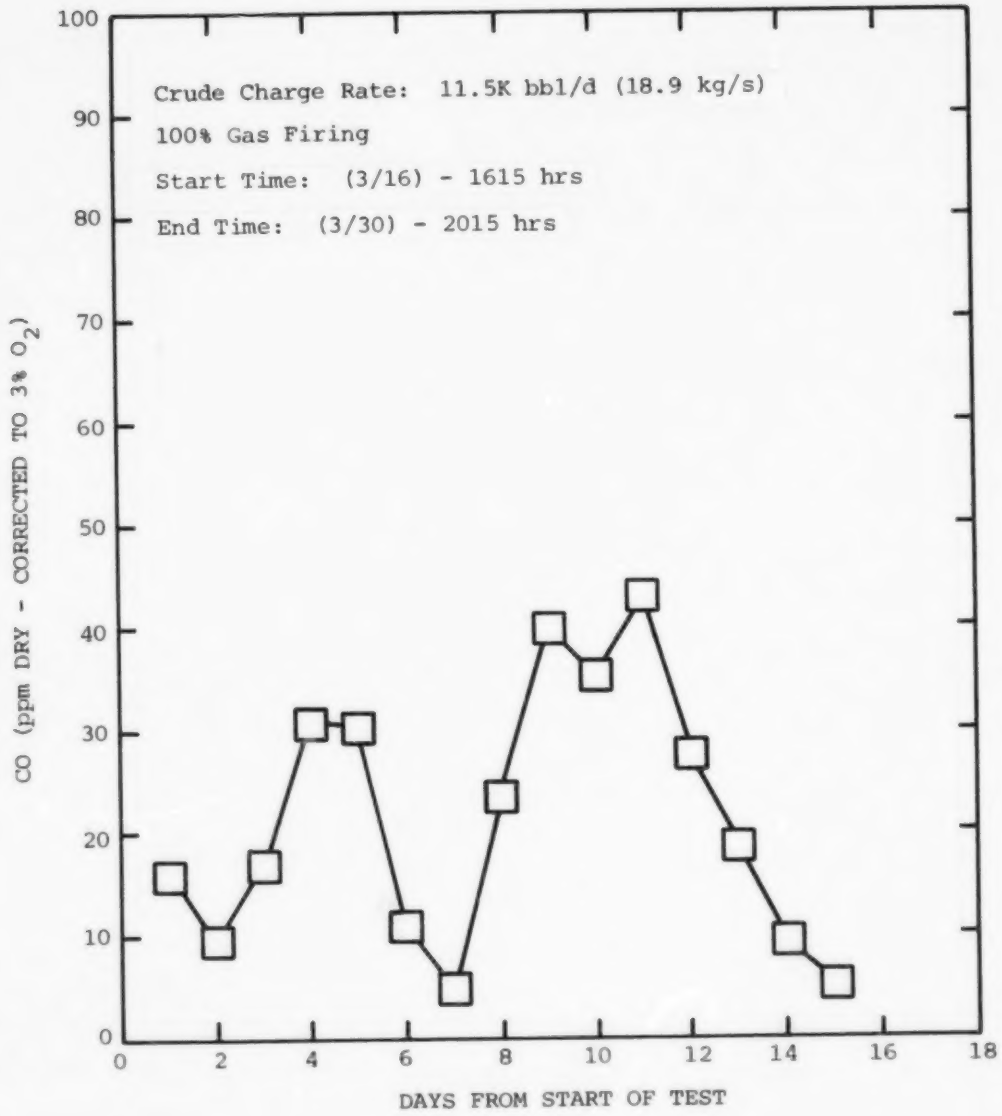

Figure 5-4. Stack CO Concentration as a Function of Time from Start of Staging Air Test

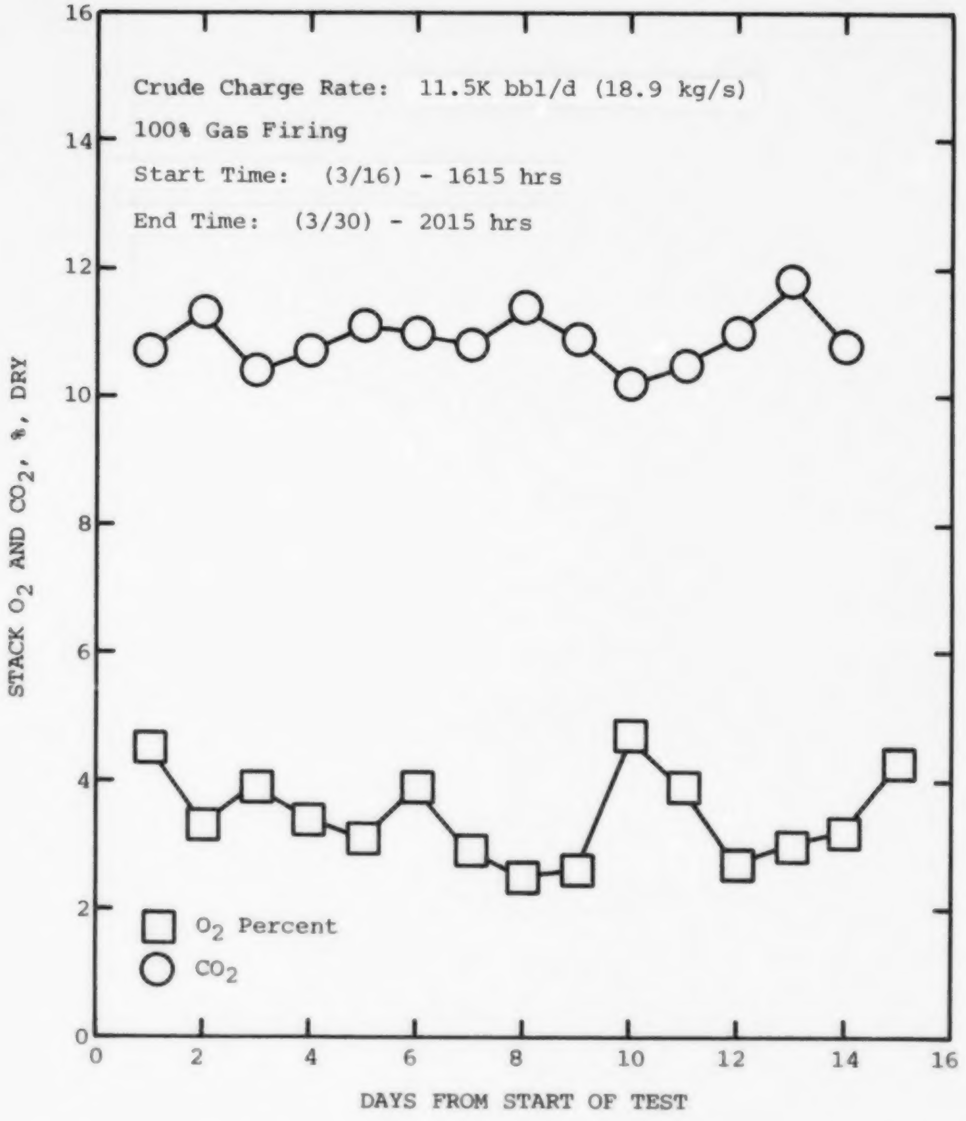

Figure 5-5. Stack O_2 and CO_2 Concentration as a Function of Time from Start of Test

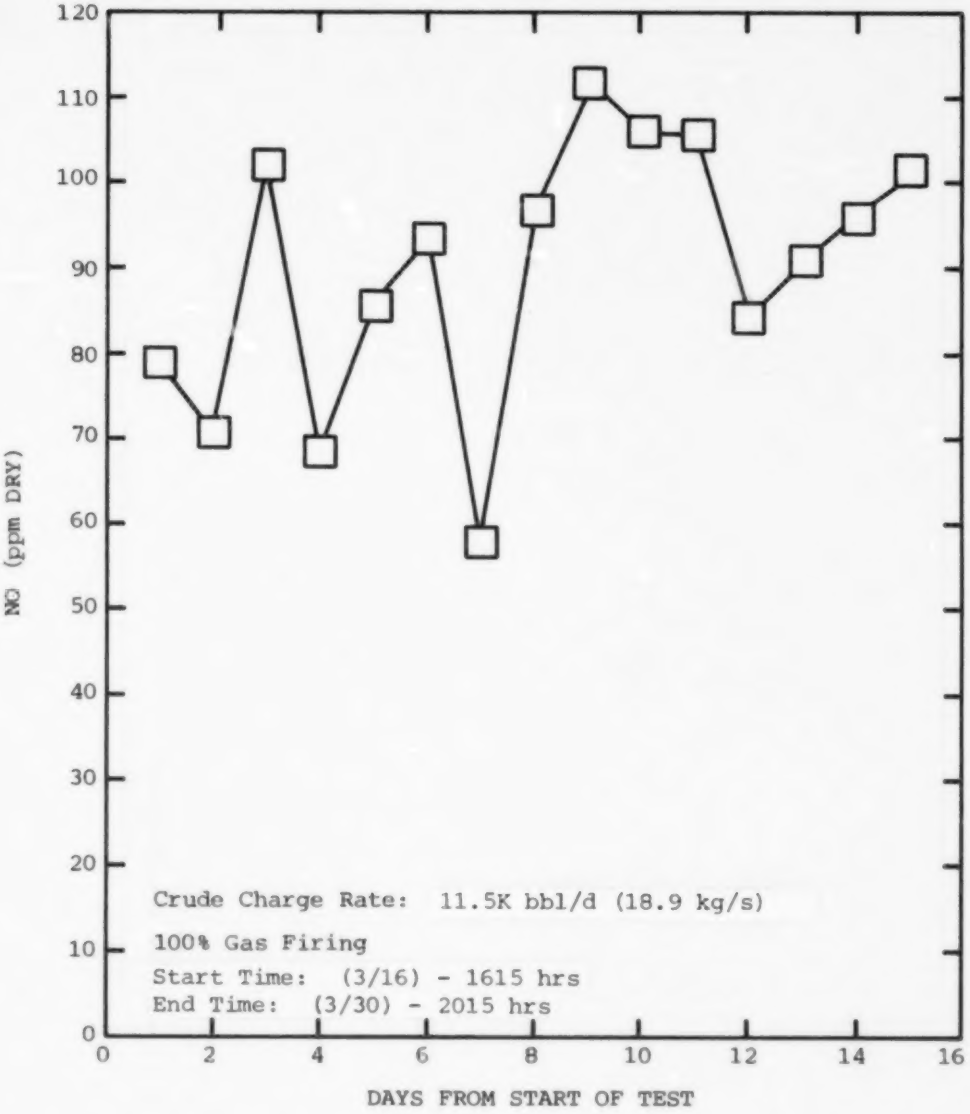

Figure 5-6. Stack NO Concentration as a Function of Time from Start of Test

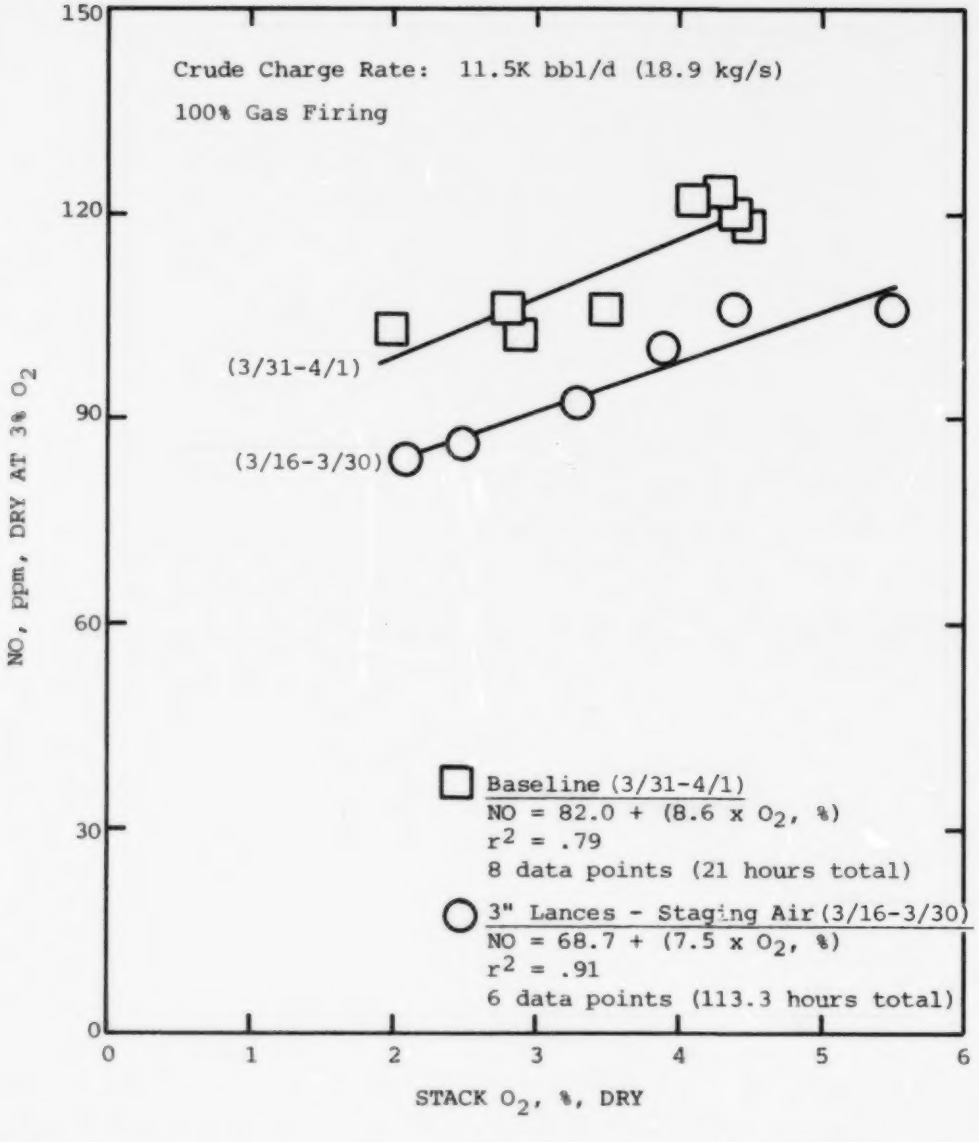

Figure 5-7. NO versus O_2 under Baseline and Staging Conditions

($r^2 = 0.78$). Calculations with the linear curve fit equations were performed to determine the extent of NO reduction with staging only (SCA) and a combination of staging and low excess air (SCA + LEA). The NO reduction from baseline is about 15 percent with staging only and is about 28 percent with staging and low excess air.

Graphical analyses of the baseline and staged air emission rates showed the data to be normally distributed. Figure 5-8 presents a normal probability curve of the NO emission rate for a nominal 2 and 4 percent O_2 operating condition. The data used to generate the probability are tabulated in Appendix C (page C-42). A linear curve fit of the data shows that the data are normally distributed. The curve shows that the mean NO value is 43 ng/J (0.10 $lb/10^6$ Btu) for the 2 percent O_2 setting. At the 4 percent O_2 setting, the mean NO value is 51 ng/J (0.12 $lb/10^6$ Btu). The geometric dispersion is 1.03 for both curves.

The emission measurements for this heater were also calculated in terms of firing rate. The units for the emission rate are pounds/million Btu or nanograms/Joule. An F-factor was used to calculate the emission rate in the unit of the standard. It reduces the amount of data necessary to complete the emission rate calculation. The F-factor for making emission rate calculations is developed from a chemical and combustion analysis of the fuel burned. The F-factor is the ratio of the theoretical volume of dry gases (V_t) given off by complete combustion of a known amount of fuel, to the gross caloric value of the burned fuel (HHV).

$$F_d = \frac{\text{Volume Dry Combustion Gases}}{\text{Gross Caloric Value}} = \frac{V_t}{\text{HHV}}$$

An average fuel firing factor, F_d, was calculated for both the three nonscrubbed refinery gas samples and the two absorber gas samples. The F_d factor for the three nonscrubbed refinery gas samples is

$$8601 \frac{\text{dscf}}{10^6 \text{ Btu}} \left(2.31 \times 10^{-7} \frac{\text{dscm}}{\text{J}}\right)$$

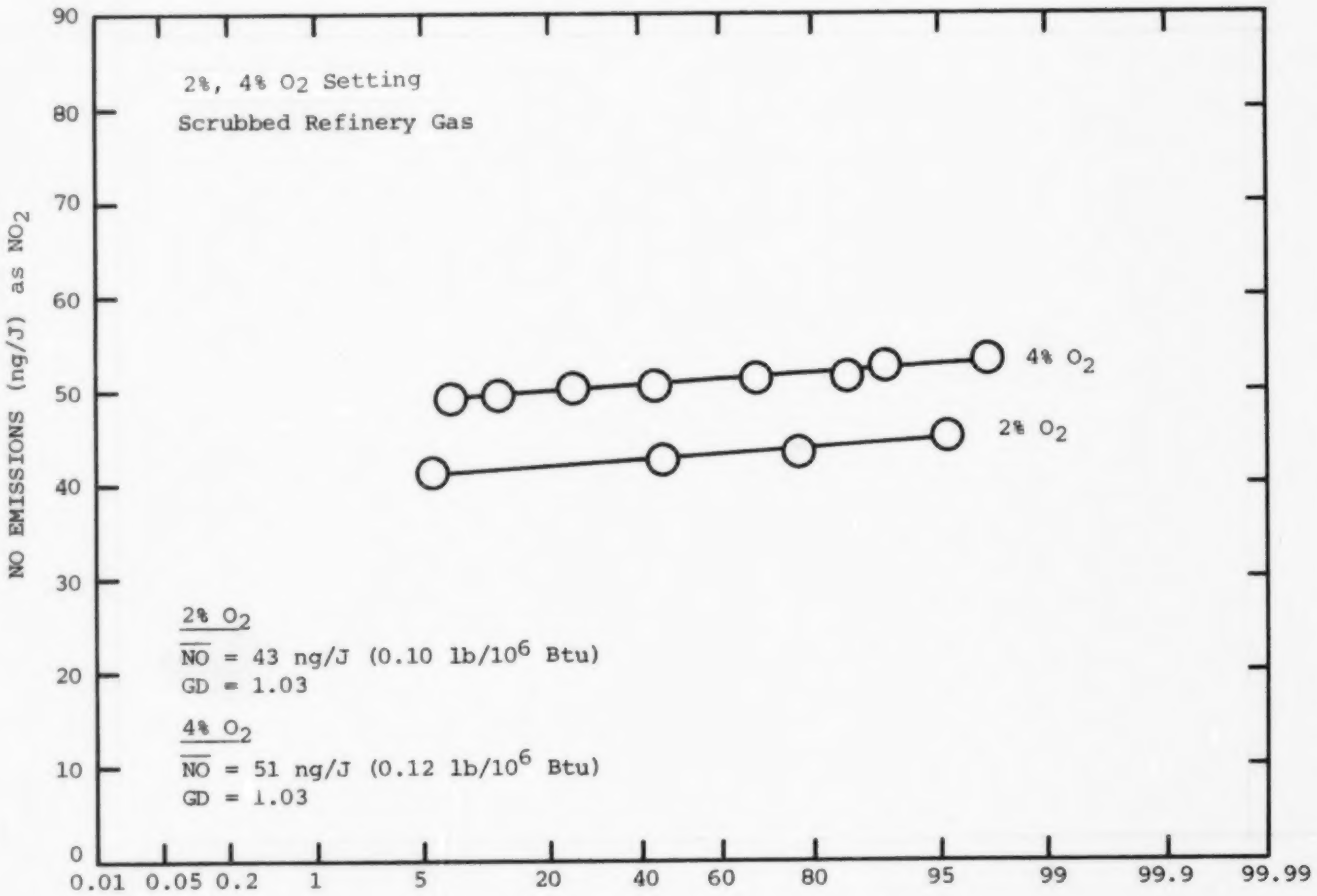

Figure 5-8. Normal Probability Curve of NO Emissions Crude Heater 15-day Field Test

with a standard deviation of

$$27 \frac{\text{dscf}}{10^6 \text{ Btu}} \left(1 \times 10^{-9} \frac{\text{dscm}}{\text{J}}\right) .$$

The coefficient of variation for F_d is 0.3 percent indicating a very small deviation from the average value. This F_d factor was used for converting the CO and NO data to a mass emission basis (nanograms per Joule) for the time period of March 14 (1215 hours) to March 25 (1800 hours).

The F_d factor for the two absorber gas samples is

$$8523 \frac{\text{dscf}}{10^6 \text{ Btu}} \left(2.29 \times 10^{-7} \frac{\text{dscm}}{\text{J}}\right)$$

with a standard deviation of

$$20 \frac{\text{dscf}}{10^6 \text{ Btu}} \left(1 \times 10^{-9} \frac{\text{dscm}}{\text{J}}\right) .$$

The coefficient of variation for F_d is 0.2 percent indicating a very small deviation from the average value. This F_d factor was used for converting CO and NO data to a mass emission basis (nanograms per Joule) for the time period of March 25 (1800 hours) to April 1 (0845 hours).

The conversion of ppm NO_x as NO_2 to ng/Joule was made by using the procedure outlined in the Federal Register/Vol. 44, No. 113, Monday, June 11, 1979, paragraph 5.3, "Calculation of Emission Rate." The emission rate at operating conditions is calculated from the following relationship:

$$E = C_d \, F_d \, \frac{20.9}{20.9 - \%\, O_2}$$

where:

E = Pollutant emission rate, lb/10^6 Btu (ng/J)

C_d = Pollutant concentration, lb/dscf (ng/dscm)

F_d = Fuel firing factor, dry basis, dscf/10^6 Btu (dscm/J)

To convert from ppm NO_x to lb/dscf, multiply by 1.194×10^{-7}. To convert from ppm NO_x to ng/dscm, multiply by 1.912×10^{6}. These conversion factors are based on the molecular weight of NO_2.

There is a significant difference (calculated test statistic) between the average F_d for nonscrubbed refinery gas and absorber gas. However, the error associated by using an average F-factor rather than an instantaneous F-factor for each fuel is at most one percent. This analysis is based on the relatively few samples collected.

Table 5-4 shows the summary of the 15-day test results for NO reductions below baseline for a crude heater with staged combustion air. The results are based on absorber gas firing.

From an operations viewpoint, the natural draft staged air provided no problems regarding flame impingement, CO or smoking problems for the nominally set stack oxygen concentration of 2 percent and above. Heat flux distribution showed little variation from baseline conditions. Considerable discoloration of the stainless steel lances was noted. While surface discoloration was noticeable, the staged air lances suffered no other physical damage.

TABLE 5-4. SUMMARY OF 15-DAY TEST RESULTS FOR NO REDUCTION BELOW BASELINE FOR A PROCESS HEATER WITH NATURAL DRAFT STAGED COMBUSTION AIR

	Baseline NO	SCA at 4% O_2	LEA (2% O_2)	SCA + LEA (2% O_2)
ppm at 3% O_2	116	99	99	84
ng/J	59	50	50	43
lb/10^6 Btu	0.14	0.12	0.12	0.10
% Reduction from Baseline	--	15	15	28

SECTION 6.0

DISCUSSION OF RESULTS

Since the 4-inch ports (greater staging air capability) provided more staging air than the other configurations, the 4-inch ports were the most effective configuration for NO reduction of the three natural draft configurations examined. The physical limit for the port size and lance size is the spacing between the burners at the furnace floor and the space available at the heater bottom. For this heater, 4-inch ports were the physical limit. The difference in NO reduction between natural draft staging and forced draft staging was minimal for comparable burner equivalence ratios (Φ_B ~0.8) at a process rate of 14,000 bbl/day.

The reduction potential with the natural draft ports was not nearly as good as that shown with the forced draft staged air system previously tested. For gas fuel (from the previous 30-day test results in Reference 1), this reduction from baseline was 71 percent with lowered excess air and forced draft staged combustion air. Approximately 42 percent of the total combustion air was supplied as staged air by the blower. Similar proportions of staging air were achieved under natural draft conditions with the 4-inch ports, but the extent of reduction was not as good (approximately 50 percent with a combination of SCA + LEA).

Percent reduction in NO emissions attained with SCA and 80/20 oil-gas firing was not as good as with the 50/50 oil-gas mix discussed in Reference 1. The NO emissions reduction at normal operating O_2 was 34 percent for the 50/50 oil-gas mix but only 25 percent for the 80/20 oil-gas mix. This difference in percent reductions attained is due to the fact that the staged air fan was able to supply approximately 50 percent of the total combustion air for the 50/50 oil-gas mix and only 35 percent of the total combustion air for the 80/20 oil-gas mix.

Baseline conditions were established as 4 percent stack O_2 for 100 percent gas firing and 4 to 6 percent stack O_2 for 80 percent oil/20 percent gas firing. The 4 percent stack O_2 established for 100 percent gas firing is considered to be a normal operating level by plant personnel. The 4 percent stack O_2 baseline for 80 percent oil/20 percent gas firing was also considered to be a viable starting point by plant personnel and also would allow for direct comparison of NO emission data previously collected at the 50 percent oil/50 percent gas firing condition (Ref. 1). The baseline stack oxygen of 4 percent was initially achieved for several test days under various thermal input rates and crude charge rates. However, some test series at the low and medium loads from February 22 onward could not be run at the 4 percent baseline oxygen without making extreme stack damper and register adjustments. It is not clear why the 4 percent baseline oxygen was more difficult to achieve on certain test days. Reasons may include the crude inlet temperature change which alters the fuel input to maintain constant crude outlet temperature or the fuel composition ratio (80 percent oil/ 20 percent gas) which was not burning effectively at lower stack oxygen levels. These baseline conditions could be achieved solely with stack damper and secondary air register adjustments (i.e., no combustion modifications). The 4 percent stack O_2 for 100 percent gas firing and 6 percent stack O_2 for 80-20 oil/gas mixture was achievable under all process rates studied (55-96 percent full load). The baseline conditions were established to determine the extent of NO reduction to 2 percent stack O_2 on 100 percent gas firing and typically 3 percent O_2 on a 80-20 oil/gas mixture. Costs would be associated with oxygen controllers to control the heater automatically such that the combination of staged air and low excess air can be used for NO_x reduction and efficiency gain.

6.1 EFFICIENCY IMPLICATIONS

Efficiency gains are implied through staging and/or lowered excess air. These gains are calculated for both 100 percent gas firing conditions and 80 percent oil/20 percent gas firing conditions. The percentage fuel reduction is less than 1 percent from baseline for natural draft staged combustion air only at 2 percent and 4 percent O_2 (Section 3.3). The use of lowered excess air (4 vs. 2 percent O_2) reduces fuel use by approximately 1 percent. When combined with natural draft staged air, lowered excess air reduces fuel consumption less than 2 percent.

The efficiency gains are greater with 80 percent oil/20 percent gas firing with forced draft staged combustion air. The change in fuel consumption relative to baseline when SCA is applied is 3.5 percent for 6 percent stack O_2. Lowered excess air and forced draft staged combustion air reduces fuel consumption by 6 percent (Section 4.2).

6.2 COMPARISON WITH LABORATORY-SCALE WORK (Ref. 1)

Maximum reductions in NO_x emissions firing gas fuel were 46 percent at normal operating stack O_2 (3 percent) and 67 percent at reduced O_2 (1 percent) for the laboratory heater combustion facility. With the pilot-scale heater, the 4-inch ports provided enough naturally drafted staged combustion for approximately 45 percent NO_x reduction at an operating stack O_2 of 4 percent and a maximum of 56 percent NO_x reduction with lowered excess air plus staged air (2 percent stack O_2). It should be noted that the NO reduction is interpreted as NO_x reduction for comparison with previous results. The assumption is based on the fact that NO_x was 100 percent NO as measured in the previous pilot scale program for the same refinery crude heater (Ref. 6). If NO is assumed to be a fixed percentage of NO_x, the NO reduction and NO_x reduction percentage will be the same.

Average NO_x emissions on the laboratory-scale heater firing 100 percent No. 6 oil were 150 ng/J compared to 144 ng/J (4 percent stack O_2) for the pilot-scale heater firing 80 percent oil, 20 percent gas. Data on the subscale heater were gathered at 3 percent O_2 while the data on the pilot-scale heater were reported at 4 and 6 percent O_2. The percent reductions obtained with the pilot-scale heater were much less than the subscale heater. Percent reduction in NO_x emissions attained with SCA was 35 percent (laboratory scale) baseline O_2, 3 percent and 24 percent (pilot scale) for baseline O_2, 4 percent. At reduced O_2, 51 percent reduction in NO_x emissions was achieved with the laboratory-scale heater (3 percent to 1 percent) while 40 percent reduction was achieved with the pilot-scale heater by lowering the stack oxygen from 6 percent to 3 percent. Under all conditions tested, 3 percent stack oxygen was the lower limit of oxygen which could be operated at the 80 percent load range. CO and smoking problems were incurred at lower oxygen levels.

Two reasons for the differences in NO_x reduction are (1) the limits of the fan to provide a greater amount of forced draft staged combustion air in the pilot-scale heater and (2) difficulties of safely operating the pilot-scale heater at high oil gas ratios and still maintaining low excess air.

SECTION 7.0

COST ANALYSIS OF STAGED COMBUSTION AIR APPLIED TO A NATURAL DRAFT PROCESS HEATER

7.1 LIMITATIONS OF THE ANALYSIS

NO data gathered in this study are interpreted as NO_x data for reduction potential and cost (savings) analysis. This interpretation is made for consistent comparison between previous data (Ref. 1) and the cost analysis data presented in this section. The assumption that all NO_x is NO (no NO_2) for the data should be fairly accurate since no NO_2 was detected in the previous program for 100 percent gas firing and a combination of 50 percent gas/50 percent oil firing.

The costs and NO_x reductions discussed in this section pertain to permanent installation of a naturally drafted staged combustion air system and a forced draft staged combustion air system. These installations would be on a natural draft crude heater firing all gaseous fuel or a mixture of residual oil and gas (by heat input rate).

Costs are given in November, 1981 dollars to compare with previous KVB's estimates of material and labor costs for the forced draft system capable of handling 100 percent gas firing or a 50/50 mixture of residual oil and gas. These costs do not represent actual costs for any particular system.

Initial fixed costs, fuel savings and annual operating costs with staging air systems and/or low excess air are presented for 100 percent gas firing. Total annualized costs for 16.1 MW, 29.3 MW and 147 MW thermal input process heaters are tabulated for staged combustion air (SCA), lowered excess air (LEA), and staged combustion air plus lowered excess air (SCA + LEA). These total annualized costs are then divided by the annual NO_x reduction potential to give a dollar amount per metric ton of NO_x removed by the modification. NO_x reduction potentials are based on the parametric tests run during the two phases of testing. The annual NO_x reduction potential is given for the three heater sizes. Costs of various control technologies for NO_x reduction are compared.

7.2 INITIAL FIXED COSTS

The initial fixed costs of a permanent forced draft and natural draft staged air system for a 16.1 MW thermal input process heater are presented in Table 7-1. They apply to a system schematic essentially the same as that shown in Figure 2-1 except that all of the pipe and fittings for the forced draft system are now schedule 40 carbon steel. This is dictated by plant safety standards. The ball valves controlling air flow to each set of four lances have also been eliminated since the air distribution is nearly equal to each burner without the use of any flow control valves. Equal air distribution to each burner provided the best NO_x reduction capability during the parametric tests so it has been the guiding principle behind the permanent system design. In addition the blower size has been optimized. The permanent design uses a 2.08 m^3/s (4400 scfm) blower with a discharge pressure of 14 kPa (2 psi) and it is driven by a 44.8 kW (60 hp) electric motor.

As expected, the labor and material costs are significantly less with the natural draft staged air system ($27,000 compared to $50,000 for the forced draft system). It should be noted that the installation of an automatic O_2 or stack draft controller would be necessary to maintain the stack oxygen content at an optimum level. As reported earlier, (Ref. 1), the installed costs of an automatic draft controller (applicable only to natural draft heaters) are expected to be about $40,000 for a heater of the same size as the present test unit.

7.3 ANNUAL OPERATING AND MAINTENANCE COSTS

For the application of forced staged combustion air only, one must consider the annual blower electricity costs, the annual maintenance costs on the blower and staged air lances offset by any annual fuel savings resulting from the efficiency increases due to the addition of the SCA system.

Fuel savings which result from the application of staged combustion air at 4 percent stack O_2, the savings due to the use of lowered excess air

TABLE 7-1. INITIAL FIXED COSTS OF A PERMANENT NATURAL DRAFT VERSUS FORCED DRAFT STAGED COMBUSTION AIR SYSTEM FOR A 16.1 MW THERMAL INPUT HEATER

Item	Cost (November 1981 $)					
	Labor ($)		Material ($)		Labor and Material ($)	
	FD*	ND*	FD	ND	FD	ND
1. Civil and Structural (Foundations)	900	0	300	0	1,200	0
2. Blower, Motor, and Outlet Adapter	900	0	6,200	0	7,100	0
3. Pipe and Fittings, Lances, Installation of Couplings in Heater Floor	8,800	1,800	6,740	3,200	15,540	5,000
4. Instrumentation	50	50	250	250	300	300
5. Electrical (including starter for motor)	3,600	0	4,470	0	8,070	0
6. Engineering	8,000	4,000	300	300	8,300	4,300
7. Construction	4,000	0	2,200	0	6,200	0
8. Indirect (including taxes, contingency, etc.)	--	--	3,000	3,000	3,000	3,000
TOTALS	26,250	5,850	23,460	6,750	49,710	12,600

*FD - Forced Draft (1-1/4" lances)
ND - Natural Draft (4" ports)

only, and due to the use of SCA + LEA combined are shown in Table 7-2. The basis for the fuel savings was established in Sections 3 and 4 for the natural draft staged combustion air tests and forced draft staged combustion air tests, respectively. Baseline stack oxygen for these cost analyses was approximately 4 percent for both gas firing and 80 percent oil/20 percent gas firing. The baseline stack oxygen was demonstrated as being achievable for both gas and oil/gas firing and was considered to be a normal operating level by plant personnel. The 2 percent oxygen was established as an optimum operating condition for short term tests without additional operator supervision. Any lower stack oxygen levels would compromise heater performance and plant safety. Fluctuations in fuel flow (i.e., fuel surges) or draft would cause elevated levels of CO and smoke. Also, the convective section and stack pressure may turn positive which might result in a flashback condition. The percent decrease in fuel consumption is converted into cost savings based on the plant's gas fuel cost of $\$3.44/10^6$ Btu (Ref. 3) or \$0.01174/kW-h and the heater use factor of 0.70.

The percent decrease in fuel consumption with lowered excess air for combined gas/No. 6 oil firing is also shown in Table 7-2. The fuel savings is 3 percent for a 50 percent oil/50 percent gas blend and is 4 percent for a 80 percent/20 percent gas blend. The dollar savings is based on the fact that the plant's fuel costs are nearly equal to the plant gas costs.

Table 7-3 compares the annual costs of combustion modifications for a natural draft and forced draft staged air system. Values in parentheses represent a saving. The derivation of these costs for the forced draft system has been discussed in detail in Reference 1. The annual operating costs for the natural draft and forced draft staged air system are nearly identical when operating in the SCA + LEA mode.

7.4 COST AND SAVINGS ASSOCIATED WITH HEATER SIZE

The relationships between costs, savings, and heater size, developed in reference 1, are summarized here:

1. Initial Fixed Costs (IFC) $\propto \mathrm{MW}^{2/3}$,

TABLE 7-2. FUEL SAVINGS (NOV., 1981 $) DUE TO COMBUSTION MODIFICATIONS TO A NATURAL DRAFT PROCESS HEATER RATED AT 16.1 MW THERMAL INPUT

Modification	Fuel Firing	Percent Decrease in Fuel Consumption	Annual Savings ($)
1. Natural Draft Staged Combustion Air at 4% O_2*	100% Gas	1.1	12,760
2. Lowered Excess Air (4% O_2 → 2% O_2)	100% Gas	1.3	15,080
3. Natural Draft Staged Combustion Air + Lowered Excess Air (4% O_2 → 2% O_2)	100% Gas	1.4	16,240
4. Lowered Excess Air (4.1% O_2 → 1.8% O_2)	50% Oil/ 50% Gas	3.0	34,806
5. Lowered Excess Air (4.5% O_2 → 1.8% O_2)	80% Oil/ 20% Gas	4.0	46,408

*4% O_2 used as a representative baseline for gas firing.

TABLE 7-3. ANNUAL OPERATING COSTS (NOV., 1981 $) OF COMBUSTION MODIFICATIONS TO A NATURAL DRAFT PROCESS HEATER RATED AT 16.1 MW THERMAL INPUT

Item	SCA* Only (4% O_2)		LEA Only (4% O_2 + 2% O_2)		SCA + LEA (4% O_2 + 2% O_2)	
	FD (Ref. 1)	ND	FD (Ref. 1)	ND	FD (Ref. 1)	ND
Blower Electricity	17,855	0	0	0	17,855	0
Maintenance	1,500	175	200	200	1,500	380
(Fuel Savings)	(2,320)	(12,760)	(32,485)	(15,080)	(35,965)	(16,240)
Totals, costs (savings)	17,035	(12,585)	(32,285)	(14,880)	(16,610)	(15,860)

*SCA = Staged Combustion Air
LEA = Lowered Excess Air
FD = Forced Draft
ND = Natural Draft

2. Annual Maintenance Costs = 0.03 x IFC, thus

3. Annual Maintenance Cost $\propto MW^{2/3}$,

4. Annual Fuel Savings $\propto MW^1$, and

5. Annual Blower Electricity Costs $\propto MW^1$.

In the following sections these relationships were used to develop total annualized costs and cost/effectiveness ratios for larger heater sizes.

7.5 TOTAL ANNUALIZED COSTS

The assumptions made in determining the total annualized costs for a 16.1 MW_{th} natural draft process heater are given in Table 7-4. These assumptions are explained in detail in Reference 4 and will not be discussed here.

The total annualized costs are calculated by adding the annual costs including taxes and insurance to the annualized capital costs. These costs are presented in Table 7-5 for the following modifications applied to a 16.1 MW_{th} process heater firing gas: SCA at 4 percent O_2, LEA only, and the combination of SCA plus LEA.

To a first approximation the total annualized cost of SCA applied at 4 percent O_2 may be related to the heat input rate of the heater by using the cost scaling factors presented in Section 7.1. Calculations of total annualized costs (savings) for staged air applied at 4 percent O_2, lowered excess air only, and staged air plus lowered excess air are shown for heater sizes of 29.3 MW (100×10^6 Btu/h) and 147 MW (500×10^6 Btu/h) in Tables 7-6 and 7-7.

The costs for forced draft staged combustion air at 4 percent O_2 are plotted versus heat input rate in Figure 7-1. From that log-log plot one may determine an approximate power law for the total annualized costs. The slope of the curve shown in Figure 7-1, is approximately 0.86. Thus,

$$\frac{\text{Cost at Size 1}}{\text{Cost at Size 2}} = \left(\frac{MW_1}{MW_2}\right)^{0.86}$$

This is valid for heat input rates between 3 MW and 147 MW.

TABLE 7-4. ASSUMPTIONS MADE IN DETERMINING TOTAL ANNUALIZED COSTS

1. State and Federal Property Taxes = 11% of Initial Capital Cost
2. Insurance Charges = 0.5% of Initial Capital Cost
3. Straight-Line Depreciation Over 12 Years
4. State and Federal Income Taxes = 50%
5. Investment Tax Credit (First Year Only) = 10%
6. 100% Equity Financing (Debt/Equity = 0)
7. 15% Rate of Return
8. Capital Recovery Factor = 0.2773

TABLE 7-5. TOTAL ANNUALIZED COSTS OF COMBUSTION MODIFICATIONS ON A 16.1 MW_{th} NATURAL DRAFT PROCESS HEATER

Item	Costs (November 1981 $)					
	SCA* @ 4% O_2		LEA* Only ($4\% \ O_2 \rightarrow 2\% \ O_2$)		SCA + LEA ($4\% \ O_2 \rightarrow 2\% \ O_2$)	
	FD* (Ref. 1)	ND*	Past Tests (Ref. 1)	Current Tests	FD (Ref. 1)	ND
Annual Operating Cost (Savings)	17,035	(12,585)	(32,285)	(14,880)	(16,610)	15,860
State and Federal Taxes (11% of IFC)	5,468	1,386	4,400	4,400	9,868	5,786
Insurance (0.5% of IFC)	249	63	200	200	449	263
Subtotal, Costs (Savings)	22,752	(11,136)	(27,685)	(10,280)	(6,293)	(9,811)
Initial Fixed Costs	49,710	12,600	40,000	40,000	89,710	52,600
Annual Capital Charge	13,785	3,494	11,092	11,092	24,877	14,586
Total Annualized Costs	36,537	(7,642) savings	(16,593) savings	812	18,585	4,775

*SCA = Staged Combustion Air
LEA = Lowered Excess Air
FD = Forced Draft Staged Air
ND = Natural Draft Staged Air
IFC = Initial Fixed Costs

TABLE 7-6. TOTAL ANNUALIZED COSTS OF COMBUSTION MODIFICATIONS ON A 29.3 MW_{th} NATURAL DRAFT PROCESS HEATER

	Costs (November 1981 $)					
	SCA* @ 4% O_2		LEA* Only (4% O_2 → 2% O_2)		SCA + LEA (4% O_2 → 2% O_2)	
Item	FD* (Ref. 1)	ND*	Past Tests (Ref. 1)	Current Tests	FD (Ref. 1)	ND
Annual Operating Cost (Savings)	30,508	(22,961)	(58,821)	(27,146)	(30,722)	(28,989)
State and Federal Taxes (11% of IFC*)	8,151	2,066	6,559	6,559	14,709	8,625
Insurance (0.5% of IFC)	370	94	298	298	669	392
Subtotal, Costs (Savings)	39,029	(20,801)	(51,964)	(20,289)	(15,344)	(19,972)
Initial Fixed Costs	74,098	18,782	59,624	59,624	133,722	78,406
Annual Capital Charge	20,547	5,208	16,534	16,533	37,081	21,742
Total Annualized Costs	59,576	(15,593) savings	(35,430) savings	(3,755) savings	21,737	1,770

*SCA = Staged Combustion Air
LEA = Lowered Excess Air
FD = Forced Draft Staged Air
ND = Natural Draft Staged Air
IFC = Initial Fixed Costs

TABLE 7-7. TOTAL ANNUALIZED COSTS OF COMBUSTION MODIFICATIONS ON A 147 MW_{th} NATURAL DRAFT PROCESS HEATER

	Costs (November 1981 $)					
	SCA* @ 4% O_2		LEA* Only (4% O_2 $\rightarrow$ 2% O_2)		SCA + LEA (4% O_2 $\rightarrow$ 2% O_2)	
Item	FD* (Ref. 1)	ND*	Past Tests (Ref. 1)	Current Tests	FD (Ref. 1)	ND
Annual Operating Cost (Savings)	159,442	(115,739)	(295,728)	(136,813)	(158,799)	(146,618)
State and Federal Taxes (11% of IFC*)	23,887	6,055	19,221	19,221	43,108	25,276
Insurance (0.5% of IFC)	1,086	275	874	874	1,959	1,149
Subtotal, Costs (Savings)	184,415	(109,409)	(275,633)	(116,718)	(113,732)	(120,193)
Initial Fixed Costs	217,156	55,042	174,738	174,738	391,894	229,780
Annual Capital Charge	60,217	15,263	48,455	48,455	108,672	63,718
Total Annualized Costs (Savings)	244,632	(94,146)	(227,178)	(68,263)	(5,060)	(56,475)

*SCA = Staged Combustion Air
LEA = Lowered Excess Air
FD = Forced Draft Staged Air
ND = Natural Draft Staged Air
IFC = Initial Fixed Costs

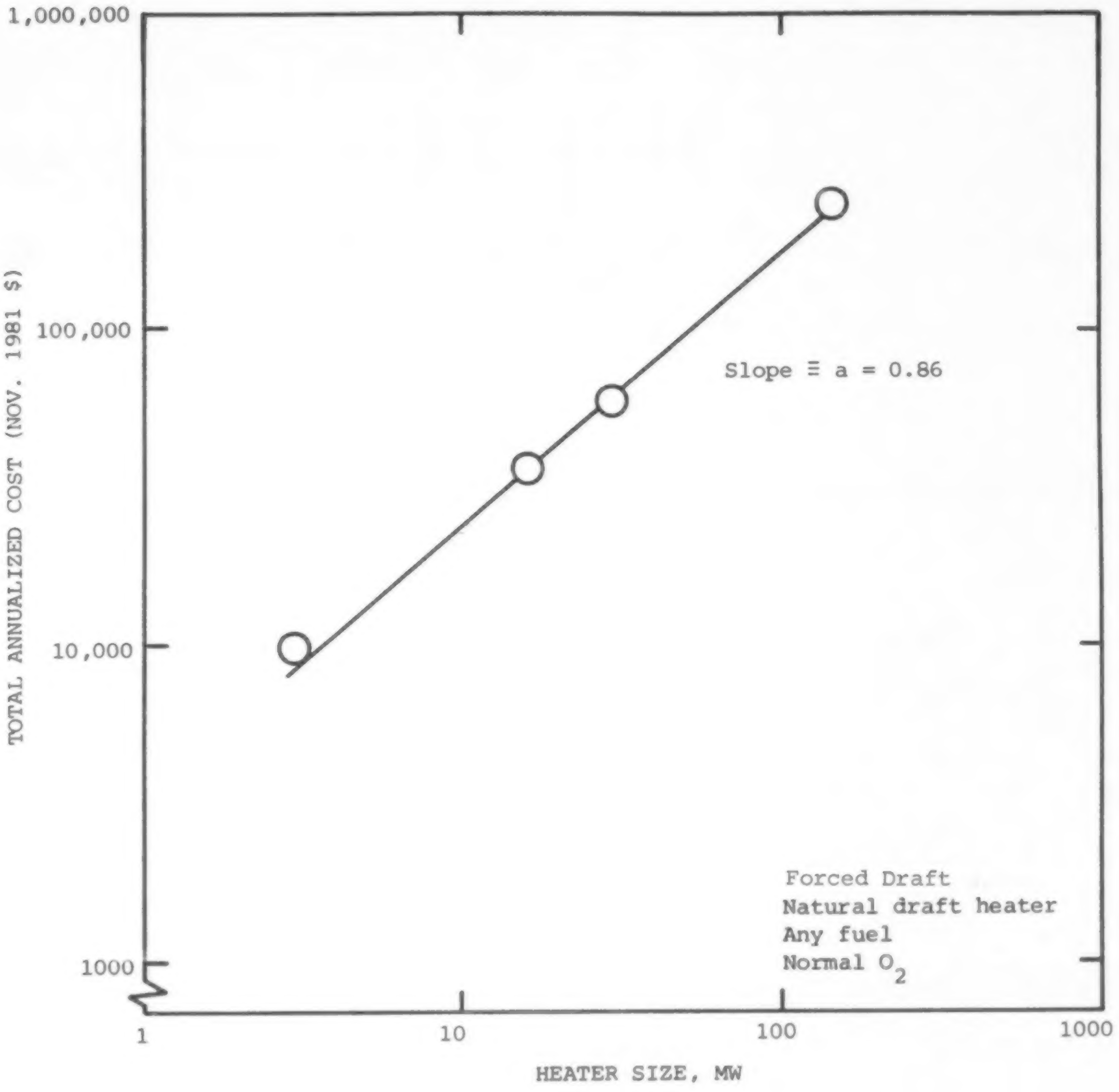

Figure 7-1. Total annualized costs as a function of design heat input capacity for natural draft process heaters with staged combustion air at normal stack oxygen.

The costs for natural draft staged combustion air at 4 percent O_2 are plotted versus heat input rate in Figure 7-2. Using an approximate power law for annualized costs, the slope of the curve is determined to be approximately 1.14. Thus,

$$\frac{\text{Cost at Size 1}}{\text{cost at Size 2}} = \left(\frac{MW_1}{MW_2}\right)^{1.16}$$

This is valid for heat input rates between 3 MW and 147 MW.

One observes from Tables 7-5, 7-6, and 7-7 that the savings with lowered excess air are smaller for the current work than previous work (Ref. 1). The fuel savings with lowered excess air and gas firing for this study was 1.3 percent compared to 2.8 percent in the previous study. In either case, it will clearly be advantageous to apply this modification (LEA) from the standpoint of economics alone.

Naturally drafted staged air and lowered excess air show a small annualized cost at the 16.1 and 27.3 MW thermal input rates considered. An apparent anomaly exists at thse two thermal input rates. Annualized savings are realized with natural draft staged air alone and lowered excess air alone (the exception being at the annualized cost of $812 on a 16.1 MW thermal input process heater). However, the combination of staged air and lowered excess air yields a net annualized cost. The reason for this net annualized cost is that fuel savings resulting from the combination of staged combustion air and lowered excess air (1.4 percent) is not the sum of fuel savings realized by staging alone (1.1 percent) and lowered excess air (1.3 percent). These fuel savings with SCA plus LEA are more than offset by the costs for an O_2 trim system for lowered excess air. A net annualized savings is realized at the 147 MW thermal input rate. This combination modification represents a capital investment rather than a capital expense item.

Table 7-8 shows the total annualized costs for lowered excess air with 50 percent gas/50 percent oil firing and 20 percent gas/80 percent oil firing at three process rates. Lowered excess air provides increased savings as heater size increases. The lowered excess air modification is most advantageous for combination oil/gas firing.

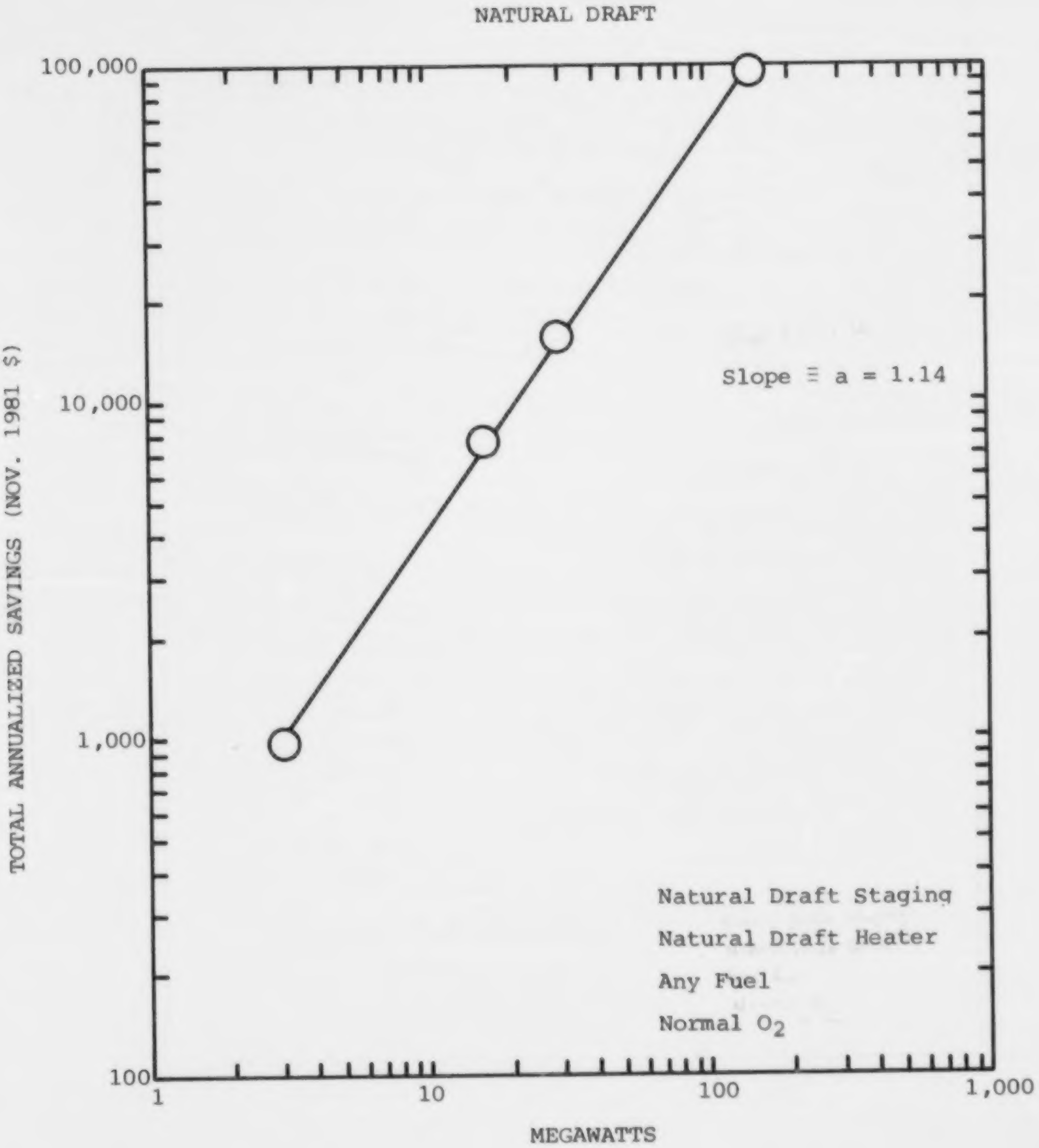

Figure 7-2. Total annualized savings as a function of design heat input capacity for natural draft process heaters with natural draft staged combustion air at normal stack oxygen.

TABLE 7-8. TOTAL ANNUALIZED COSTS OF LOWERED EXCESS AIR FOR THREE NATURAL DRAFT PROCESS HEATER SIZES FIRING AN OIL/GAS BLEND

Item	16.1 $MW_{(th)}$		29.3 $MW_{(th)}$		147 $MW_{(th)}$	
	50% Oil/50% Gas	80% Oil/20% Gas	50% Oil/50% Gas	80% Oil/20% Gas	50% Oil/50% Gas	80% Oil/20% Gas
Annual Operating Cost (Savings)	(34,606)	(46,208)	(63,043)	(84,189)	(316,920)	(422,851)
State and Federal Taxes (11% of IFC)	4,400	4,400	6,559	6,559	19,221	19,221
Insurance (5% of IFC)	200	200	298	298	874	874
Subtotal Cost (Savings)	(30,006)	(41,608)	(56,186)	(77,332)	(296,825)	(402,756)
Initial Fixed Costs	40,000	40,000	59,624	59,624	174,738	174,738
Annual Capital Charge	11,092	11,092	16,534	16,534	48,555	48,555
Total Annualized Costs (Savings)	(18,914)	(30,516)	(39,652)	(60,798)	(248,270)	(354,201)

7.6 COST/EFFECTIVENESS RATIO

The cost/effectiveness ratio of staged combustion air applied at 4 percent O_2 and of the combined SCA/LEA modification is determined here. The cost/effectiveness ratio, CE, is defined as the total annualized costs divided by the annual NO_x reduction potential to give a dollar amount per metric ton of NO_x removed by the modification.*

The annual NO_x reduction potential is given for three heater sizes in Table 7-9, based on the nanograms/joule reduction from the baseline for staging only, lowered excess air only, and the combination of staging plus lowered excess air.

These calculations assume a NO_x reduction capability of 30 ng/J for the staged combustion air system and applies to gaseous fuel. This number is the difference between the unmodified NO_x emission and the emission rate with SCA applied at 4 percent O_2. By once again assuming a use factor of 0.70 for the heater the calculation of NO_x emission reduction potential at the 16.1 MW size proceeds as follows:

NO_x Reduction Potential

$$= 16.1 \times 10^6 \frac{J}{s} \times 0.70 \times 8760 \frac{h}{y} \times 3600 \frac{s}{h} \times 30 \times 10^{-15} \frac{Mg}{J}$$

$$= 10.66 \frac{Mg}{Y}$$

It is expected that the change in emission factor due to combustion modification will hold approximately for all heater sizes so that the NO_x reduction potential will scale linearly with heat input rate.

For the combination of staged air and lowered excess air the NO_x reduction potential is assumed to be 40 ng/J which was the value for gas

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*A lower value of cost/effectiveness ratio indicates a lower cost and/or greater NO_x reduction.

TABLE 7-9. ANNUAL NO REDUCTION POTENTIAL (Mg) OF COMBUSTION MODIFICATIONS FOR THREE HEATER SIZES

Modification/Test Series	Baseline NO (ng/J)	ng/J Reduction	% Reduction from Baseline	Heater Size 16.1 MW Mg/Y*	 29.3 MW Mg/Y	 147 MW Mg/Y
Natural Draft Staged Combustion Air, 100% Gas Firing (4% O_2) / 10/8/82	67	30	45	10.7	19.4	97.7
Natural Draft Staged Combustion Air + Lowered Excess Air, 100% Gas Firing (4% $\rightarrow$ 2% O_2) / 10/27/82	73	40	55	14.2	25.9	129.7
Lowered Excess Air, 100% Gas Firing (4% O_2 $\rightarrow$ 2% O_2) / 10/27/82	67	10	15	3.7	6.8	34.1
Lowered Excess Air, 50% #6 Oil/50% Gas Firing (4.1% O_2 $\rightarrow$ 1.8% O_2)**	114	32	28	11.4	20.7	103.8
Lowered Excess Air, 80% #6 Oil/20% Gas Firing (4.5% O_2 $\rightarrow$ 1.8% O_2) / 2/11/83	176	60	34	18.1	33.0	165.4

*Mg/Y - Megagrams/year

**Ref. 1

firing. This is conservative relative to the value for gas/oil firing which was 60 ng/J.

For lowered excess air alone the NO_x reduction potential differed for the gaseous fuel and for the combination fuel. The reduction in NO_x emission factor firing gas was only 10 ng/J whereas it was 32 ng/J firing 50 percent oil/50 percent gas and 60 ng/J firing 80 percent oil/80 percent gas. The three results are shown separately in Table 7-9.

The cost/effectiveness ratio of combustion modifications applied to three heater sizes is shown in Tables 7-10 and 7-11. The values for lowered excess air with natural draft staged combustion air on the two smaller heaters are slightly positive indicating a cost in combination with a NO_x reduction. This can be a desirable situation; however, one must realize that a modification which costs money yet produces a large NO_x reduction will have a small positive cost/effectiveness ratio. This may be a desirable modification if the level of NO_x reduction is enough to achieve compliance with regulations or to offset future emissions from plant expansions. Natural draft staging and lowered excess air is a more cost effective modification for all three process heater sizes than forced draft staging plus lowered excess air.

The cost and cost/effectiveness ratio of staged combustion is compared with that of other commercially available modifications in Table 7-12 for a 29.3 MW (100 x 10^6 Btu/h) natural draft process heater. The values for low-NO_x burners and for selective non-catalytic reduction are developed from Reference 5. The values for cost/effectiveness ratio from Reference 5 have been adjusted to include state and federal taxes and a capital annualization factor of 0.2773. Fuel penalties were already included where efficiencies were reduced by modifications discussed in Reference 5, however, no credit was taken in Reference 5 for fuel savings where efficiencies increased due to a modification. Thus, the usual fuel savings due to installation of low-NO_x burners (since they often operate at lower excess air than standard burners) is not accounted for in Table 7-12. Note also that the column "Annual Operating Costs (Savings)" does not include taxes or insurance, however, these items are accounted for in the cost/effectiveness ratio column.

TABLE 7-10. COST/EFFECTIVENESS RATIO ($/Mg) OF COMBUSTION MODIFICATIONS APPLIED TO THREE NATURAL DRAFT PROCESS HEATER SIZES

Modification	16.1 MW			29.3 MW			147 MW		
	Total Annualized Costs (Savings)	Annual Reduc. Poten. Mg/Y*	Cost Effec. Ratio $/Mg	Total Annualized Costs (Savings)	Annual Reduc. Poten. Mg/Y	Cost Effec. Ratio $/Mg	Total Annualized Costs (Savings)	Annual Reduc. Poten. Mg/Y	Cost Effect. Ratio $/Mg
Natural Draft Staged Combustion Air 100% Gas Firing (4% O_2)	(7,642)	10.7	(714)	(15,593)	19.4	(804)	(94,146)	97.7	(964)
Natural Draft Staged Combustion Air + Lowered Excess Air, 100% Gas Firing (4% O_2 + 2% O_2)	4,775	14.2	336	1,770	25.9	68	(56,475)	129.7	(435)
Lowered Excess Air, 100% Gas Firing Firing (4% O_2 + 2% O_2)	812	3.7	218	(3,755)	6.8	(543)	(68,263)	34.1	(1,997)
Lowered Excess Air, 80% #6 Oil/20% Gas Firing (4.5% O_2 + 1.8% O_2)	(30,516)	18.1	(1,686)	(60,798)	33.0	(1,842)	(354,201)	165.4	(2,141)
Lowered Excess Air, 50% #6 Oil/50% Gas Firing (4.1% O_2 + 1.8% O_2)	(18,914)	11.4	(1,659)	(39,652)	20.7	(1,911)	(248,270)	103.8	(2,392)

*Mg/Y - Megagrams/year

TABLE 7-11. COMPARISON OF COST/EFFECTIVENESS RATIO ($/Mg) OF COMBUSTION MODIFICATIONS (PREVIOUS AND CURRENT WORK) APPLIED TO THREE NATURAL DRAFT PROCESS HEATER SIZES

	HEATER SIZE					
	16.1 MW		29.3 MW		147 MW	
Modification	Previous Work*	Current Work	Previous Work*	Current Work	Previous Work*	Current Work
Staged Combustion Air at 4% O_2	2,636 (forced draft)	(714) (natural draft)	2,362 (forced draft)	(804) (natural draft)	1,934 (forced draft)	(964) (natural draft)
Staged Combustion Air and Lowered Excess Air ($4\% O_2 \rightarrow 2\% O_2$)	1,089 (forced draft)	336 (natural draft)	700 (forced draft)	68 (natural draft)	(40) (forced draft)	(435) (natural draft)
Lowered Excess Air, 100% Gas Firing ($4\% O_2 \rightarrow 2\% O_2$)	(5,843)	218	(6,853)	(543)	(4,813)	(1,997)
Lowered Excess Air, 50% #6 Oil/50% Gas Firing ($4\% O_2 \rightarrow 2\% O_2$)	(1,659)	--	(1,911)	--	(2,392)	--
Lowered Excess Air, 80% #6 Oil/20% Gas Firing ($4.5\% O_2 \rightarrow 1.8\% O_2$)	--	(1,686)	--	(1,842)	--	(2,141)

*Previous Work - Reference 1

TABLE 7-12. COST (SAVINGS) OF VARIOUS CONTROL TECHNOLOGIES APPLIED TO A 29.3 MW NATURAL DRAFT PROCESS HEATER

Type of Control	NO_x ng/J Reduction	Approximate Percent NO_x Reduction	Installed Capital Cost $/MW	Annualized Costs (Savings)	Annual Operating Costs (Savings) $/Year	Annual NO_x Reduction Potential (Mg)	Average Cost/ Effectiveness Ratio $/Mg	$/lb
Lowered Excess Air (gas fuel)	8	15	2,035	(35,430)	(58,821)	5.2	(6,853)	(3.11)
Low-NO_x Burners	20	35	2,915	33,506	--	12.9	2,599	1.18
Selective Noncatalytic Reduction	28	50	4,266	94,707	46,089	18.3	5,176	2.35
Forced Draft Staged Combustion Air, Normal O_2 (gas fuel)	39	60	2,529	59,576	30,508	25.2	2,362	1.07
Forced Staged Combustion Air, Low O_2 (gas fuel)	47	71	4,563	21,737	(30,722)	31.1	700	0.32
Natural Draft Staged Combustion Air, Normal O_2 (gas fuel)	30	45	641	(15,593)	(22,961)	19.4	(804)	(0.37)
Natural Draft Staged Combustion Air, Low O_2 (gas fuel)	40	55	2,676	1,770	(28,989)	25.9	68	0.03

From Table 7-12, one observes that for a natural draft heater firing gas fuel both the percent NO_x reduction and the cost effectiveness of staged combustion compare favorably to other commercially available combustion modification techniques. Lowered excess air is certainly the most desirable modification from a financial standpoint (savings of $6,853 per Mg NO_x reduction), however it offers the least NO_x reduction capability (15 percent). A natural draft staged combustion air system without an O_2 trim system also offers an attractive cost/effectiveness ratio (savings of $806 per Mg NO_x reduction), but has a much better NO_x reduction capability of 45 percent.

The costs (savings) of a staged combustion air system on a natural draft heater may be looked at in another way. The additional cost of NO_x control per barrel of oil produced may be calculated for the present test heater as follows:

$$\frac{\Delta\text{Cost}}{\text{Unit of Throughput}} = \frac{\text{Total annualized cost of } NO_x \text{ control}}{\text{Annual Crude Throughput}}$$

For the present heater this works out to 5.5¢/m^3 (0.9¢/bbl) for forced draft SCA applied at 4 percent O_2 and a savings of 0.0122¢/m^3 (0.002¢/bbl) for natural draft SCA applied at 4 percent O_2.

SECTION 8.0

QUALITY ASSURANCE

The objective of this section is to not only document data quality but also discuss some of the limitations of the data and problems associated with attaining quality assurance. Results of an internal audit are also presented in this section as well as Appendix E.

8.1 ASSESSMENT OF DATA QUALITY

Assessment of data quality is reviewed for procedures used in collecting and processing data, quantitative analysis, and limitations of data and their use. The following discussion is geared for evaluating the attainment/nonattainment of quality assurance and quality control objectives for the data base on a qualitative as well as a quantitative basis (i.e., precision, accuracy, representativeness, completeness, comparability).

8.1.1 Procedures for Collecting and Processing Data

Frequent calibrations were conducted as one means for achieving valid data. The gaseous emissions instruments were zeroed and spanned once an hour during baseline conditions and twice an hour during the parametric tests with either natural draft or forced draft staged air. Prior to recording data during a parametric test, the heater operation was checked to insure that conditions were steady. The evaluation of steady operation was based on emissions data (steady O_2 with acceptable CO emissions) with control room data. When heater operation was deemed acceptable for data collection, data were collected every minute for a mininum of twenty minutes. More data were collected if some heater operation perturbation occurred during the test (e.g. gas fuel change).

Reference baseline tests were conducted at the beginning and end of most test days to establish confidence by which the percentage NO reduction is calculated for staged air tests. The reference baseline was based on a nominal stack O_2 of four percent with 100 percent gas firing and six percent with 80 percent oil/20 percent gas firing. If a major type of operational change occurred during a test series (e.g. change from absorber gas to plant fuel gas firing), some previously completed parametric tests with absorber gas firing for that day would be repeated with the fuel switchover. A reference baseline test would then be conducted at the end of the day with the plant fuel gas. Control room operating data were collected during each and every test to insure that any significant changes from test to test were duly noted and would help explain any apparent anomalies. The ongoing operations checks for fuel type, fuel flow, crude charge inlet temperature, and process rate (bbl/day) were vital to validate data collected.

Statistically, refinery emissions data were presented in this report in terms of the arithmetic mean, standard deviation and the 95 percent confidence interval. During the ongoing data validation in the field, data outliers due to the automatic drain system on the condenser or calibration data accidentally recorded as sample data were eliminated from consideration for further statistical treatment. The large standard deviations calculated for some of the NO emissions data (e.g. baseline testing prior to the 15-day test with natural draft staging) were particularly meaningful for indicating some type of fuel composition change during the course of testing where O_2 emissions data were fairly constant.

8.1.2 Data Quality Documentation

The data quality is documented for precision, accuracy, completeness, representativeness and reproducibility. A definition for each of the five parameters is included prior to discussion of the data collected during this program. Accuracy is a measure of the bias in a system determined by comparison of the measured value and reference value. Precision is best expressed in terms of the standard deviation for a measure of mutual agreement among individual measurements. Completeness is a measure of the amount of valid data obtained from a measurement system compared to the amount that was expected to be obtained under correct normal conditions. Representativeness expresses the degree to which data accurately and precisely represents a sampling point or condition. Comparability expresses the confidence with which one data set can be compared with another (either through redundant tests at similar process conditions or through analysis of other reports with process heater data such as Ref. 1).

The precision and accuracy of the TECO 10A analyzer for NO_x measurement was assessed by an internal audit. The result of that test are presented in the next section. Precision and accuracy of the other instruments have been assessed in previous studies (Ref. 1), but were not repeated for these test series.

Table 8-1 summarizes the completeness goals for this program and the attainment/nonattainment of these goals. Completeness objectives were satisfied for NO, O_2, SO_2, CO_2/CO during the tests with 100 percent gas firing. N_2O and SO_2/SO_3 measurements were made in addition to the gaseous emission data with 80 percent oil/20 percent gas firing tests. The completeness objectives were not satisfied for NO_2, SO_2 and hydrocarbon emission during the combined oil/gas-fired tests. Some SO_2 data were collected with SO_3 data from the Goksoyr Ross tests. Two Goksoyr Ross tests were run at both a baseline and low NO_x condition for repeatability of results. The average baseline SO_2 from the nominal 80 percent oil/20 percent gas firing condition was 436 ppm, dry at three percent O_2, which compares to an average reading of 500 ppm, dry at three percent O_2 as measured by the Dupont SO_2 analyzer. The percentage difference in the two readings is approximately 13 percent.

During the long term testing with 100 percent gas firing and the three-inch lances for natural draft staging, gaseous emissions measured were NO, O_2, CO_2 and CO. The completeness criteria were satisfied for these four gaseous species during the long term test (i.e. at least 90 percent of the total possible data points were valid data points). A completeness of approximately 83 percent was established for the baseline data based on three days of testing. Although the completeness for the baseline tests does not satisfy the governing criteria, it should be noted that the length of testing was projected beyond the original anticipated baseline test length of two days. A field technician was on the jobsite everyday to insure that the instruments were calibrated at least once daily and that the sample system was in good working order.

TABLE 8-1. COMPLETENESS OBJECTIVES

		Parametric Tests		Long Term Test (100% Gas Firing)	
Measurement Parameter (Method)	Completeness Goal (%)	100% Gas Firing	80% Oil/20% Gas Firing	Baseline	Staging
NO (monitor)	90	✓	✓	x	✓
NO_2 (monitor)	50	x	x	–	–
SO_2 (monitor)	90	✓	x	–	–
O_2 (monitor)	90	✓	✓	x	✓
CO_2/CO (monitor)	90	✓	✓	x	✓
Opacity (observes)	90	NA	✓	–	–
Hydrocarbon (GC)	90	x	x	–	–
SO_3 (ST)	70	NA	✓	–	–
N_2O (GS)	70	NA	✓	–	–
Particulate (ST)	70	NA	✓	–	–
Particle Size (ST)	70	NA	✓	–	–

(GC) = gas chromatograph with sample obtained in evacuated flask

(GS) = grab sample of liquid or solid material obtained in appropriate container, delivered to laboratory for analysis

(ST) = sample extraction train

NA = not applicable

Two particulate tests were run at the nominal firing rate of 80 percent oil/20 percent gas baseline condition and were within the ±10 percent allowable range for isokinetics (~107 percent isokinetic). Total particulates (dry and condensible) were 42.44 nanograms per joule and 43.60 nanograms per joule, respectively. The mean emission factor for total particulates was 43.02 nanograms per joule with a standard deviation of 0.82. The calculated coefficient of variation for the two baseline tests was 1.9 percent indicating excellent repeatability for this test series.

Two particulate tests were also run at the nominal firing rate of 80 percent oil/20 percent gas with forced draft staged air. The isokinetics for one of the tests was 111.5 percent (falling just outside the ±10 percent allowable range) while the other test was 109.3 percent. Total particulates (dry and condensible) were 43.6 nanograms per joule and 75.9 nanograms per joule, respectively. The mean emission factor for total particulates was 59.8 with a standard deviation of 23 nanograms per joule. The calculated coefficient of variation for the two tests with forced draft staged air was 38 percent, indicating poor repeatability for this test series. Time did not allow for a third particulate test at the low NO condition.

Table 8-2 shows the fuel samples collected during the testing and those analyzed. The host site analyzed the twenty-one gaseous fuel samples for hydrocarbons and heat of combustion. An independent lab was used to analyze four of the fifteen oil samples for carbon, hydrogen, ash, nitrogen, sulfur, oxygen by difference, heat of combustion (Btu/lb) and API Gravity at 60°F. Although the number of fuel samples was considerably less than the total number of testing days and tests conducted during this study, it was felt that the absorber gas sample analysis and No. 6 fuel oil samples analyses were representative of these fuels burned during the test period. Statistical treatment ofthe analysis (i.e. standard deviation) showed that these fuel analyses were fairly consistent. The variability of these analyses was much less than those for the plant fuel gas. As mentioned in Section 2.0, plant fuel gas can consist of any or all of the following components:

- LPG and crude vapors
- Gases from No. 2 fuel gas drum

TABLE 8-2. FUEL SAMPLE COLLECTION AND ANALYSIS INVENTORY

Test Conditions	Fuel Sample	No. of Samples Calibrated	Number Analyzed
100% Gas Firing (15 test days)	Absorber Gas	6	6
	Fuel Gas	2	2
Nominal 80% Oil/20% Gas Firing (20 test days)	Absorber Gas	3	3
	Fuel Gas	5	5
	#6 Oil	15	4
Long Term Test, 100% Gas Firing, Baseline and 3" Lances, Natural Draft Staged Air (18 test days)	Absorber Gas	1	1
	Fuel Gas	3	3
	Natural Gas	1	1

- Propane from depropanizer accumulator
- Western Gulf gas
- Reabsorber dry gas (nonscrubbed)
- Southern Cal gas

Plant fuel gas samples reflected these extremes, based on the several analyses done. When baseline tests were conducted prior to and after the long term test with natural draft staging, fuel variability (plant fuel gas) was evident with NO concentration (Table 5-2). For the first two days of baseline testing, NO ranged from 70 ppm, dry at three percent O_2 (nonscrubbed refinery and Southern Cal gas) to 160 ppmV dry at three percent O_2 (nonscrubbed refinery gas only) for constant stack oxygen. This variability in NO concentration was considerably less during the last 24 hours of baseline, when absorber gas was burned in the heater. From a QA viewpoint, more fuel samples were needed when the NO concentration was swinging between 70 and 160 ppmV, dry at three percent O_2. These fuel samples analyses would have been informative regarding the effect of gas fuel composition change on NO emissions. To reflect the time variable NO emissions due to plant fuel gas burning, a continuous on-line gas chromatograph would be needed to fully document fuel composition with NO emissions.

8.1.3 Limitations of Data and Their Use

The pollutant emission data cited in this report pertain to one specific classification of refinery process heaters, i.e. vertical cylindrical natural draft crude heaters. These data should not be used to estimate mean emissions from other types of heaters or to predict emission reduction potentials of combustion modifications until the modifications have actually been carried out on the different heater types.

NO_x measurements were made on a dry basis; thus all emissions data and reduction potentials are reported for NO. Previous work on the same refinery heater with 100 percent gas firing and 50 percent oil/50 percent gas firing indicated that NO_x measured on both a dry and wet basis were the same (no NO_2 detected).

During the combination oil/gas firing tests, baseline tests for particulates and SO_2/SO_3 were determined under normal heater operating conditions while the staging tests for particulates and SO_2/SO_3 measurement were conducted under abnormal operating conditions (i.e. a heavily sooted correction section). This unusual operating condition rendered impossible similar fuel firing conditions as at baseline. Repeat baseline tests were not run at this operating condition due to time constraints. Interpretation of the particulate and SO_2/SO_3 data must be tempered by this awareness of changes in heater operation.

8.2 INTERNAL AUDIT

An internal audit was conducted on the jobsite by the KVB Quality Assurance Officer. The audit included the following items:

- Response time check as per EPA Method 20
- Stability check of TECO 10A Analyzer
- Accuracy of TECO 10A Analyzer with three NO span bottles of known concentration
- NO loss through sampling system (sampling probe to instrument)

Response time checks were run on the TECO 10A analyzer as per Method 20. An EPA protocol 1 certified span gas concentration of 440.6 ppm NO was used for the test. Three upscale and downscale response time tests were run to establish precision for system response time. The upscale response time (stable zero reading to a stable sample reading) was 75.3 seconds with a standard deviation of 2.5 seconds. The 90 percent instrument response time (sample reading to 90 percent of the span value) averaged 65.19 seconds with a standard deviation of 2.0 seconds. The average downscale response time (stable sample reading to stable zero reading) was 76.7 seconds with a standard deviation of 5.8 seconds. The 90 percent instrument response time (span reading to stable sample reading) averaged 65.73 seconds with a standard deviation of 4.96 seconds. Sampling system response time defined as the slower of the two average times was 75.3 seconds (upscale reading) and the percent deviation from the slower system response time was 1.9 percent. The response time tests showed very good agreement between upscale and downscale response times.

A stability check of the TECO 10A Analyzer was done with the EPA protocol 1 span gas described previously. The instrument measured NO to less than 1 percent of the delta between the measured NO and true NO value in 30 seconds and to less than 0.5 percent of the delta between the measured NO and true NO value in two minutes.

Three calibration bottles of known NO concentrations were used to determine the accuracy of the TECO 10A Analyzer. Accuracy is determined from the difference of the instrument reading (X) with the true value of the gas (T) as listed by the gas manufacturer. The 0-1000 ppm range was used for all nine readings (three per test).

The first test was with a known gas concentration of 68.2 ppm NO rated to an accuracy of 1 percent (±0.7 ppm). The known value was measured as 64.3 ppm average with a standard deviation of 0.6 ppm. Since the accuracy of the TECO is 1 percent of full scale (±10 ppm) and the accuracy requirement specified by the QA plan is ±20 percent, the accuracy of this test (5.72 percent) was well within specifications.

A second certified span calibration bottle with a known concentration of 200.8 ppm NO rated to an accuracy of 1 percent (±2 ppm) was measured as 194.3 ppm based on the average of three readings. The accuracy of the instrument based on this reference value was 3.24 percent which falls within the accuracy criteria of 20 percent specified in the quality assurance manual.

The third span bottle with known concentrations of 602 ppm NO, 30 percent CO_2 was used to check instrument accuracy on the upper end of the 0-1000 ppm scale. The indicated NO concentration averaged 558 ppm with a standard deviation of 1.7 ppm. Although the accuracy of 7.31 percent was higher than instrument accuracy, the delta between the measured and true value still satisfies the quality assurance objectives. The delta can be explained by the previously demonstrated CO_2 interference with the photochemical dissociation reactions in the TECO analyzer (Ref. 7).

Another test was conducted to determine if a substantial gain or loss in NO is observed in the sampling system from the sample probe to the instrument. An EPA protocol 1 certified span gas of 440.6 ppm NO/442.7 ppm NO_x was used for this test. An NO loss of 2 ppm on the 0-1000 ppm scale was observed. This small difference (0.5 percent) is considerably less than the instrument accuracy (±10 ppm) on the 0-1000 ppm scale. The test enables one to avoid sending the calibration gas through the entire sample system every time a calibration of the instrument is required.

In addition to the jobsite audit, internal lab procedure and calculation checks were performed for EPA Methods 6 and 8. Also a test problem was completed in QA procedures for EPA Methods 5 and 6. Pseudo test samples consisting of completed data sheets and SO_2 solutions were presented to the field personnel for lab analysis (titrations with standards) and calculations. The marked samples are known solutions of sulfuric acid in peroxide absorbing solution. The calculated values of SO_2 were compared with the values known from the standarized solutions made up by the QA officer. The results are presented in Appendix E. Gas volume calculation (SDCF) error averaged 0.0025 percent where errors of less than 0.1 percent are considered to be the same values (QA Handbook). The computed pseudo-SO_2 concentration errors averaged + 1.5 percent which is significantly better than the 6 percent error reported in Section 3.5 of the QA Handbook.

8.3 QA PROBLEMS AND SOLUTIONS

The biggest concern for evaluating NO reduction potential with natural or forced draft staged air was insuring that heater operations stay as steady as possible from test to test. Heater operating data were monitored for every test to determine if, for example, a gas fuel switch or crude oil inlet temperature change had occurred which might affect NO emissions. If changes did occur (as happened on several occasions), a new baseline was established from which NO reduction potential with natural or forced draft staged air could be evaluated under similar operating conditions to the baseline. This technique helped establish the confidence levels from which staged air lances could be judged for NO reduction potential.

A problem with data comparison cannot be avoided when discussing the SO_2/SO_3 and particulate data collected under baseline and low NO_x operating conditions (nominal 80 percent oil, 20 percent gas firing). The convection section was unavoidably plugged during the low NO_x tests while the convection section was unplugged for the baseline particulate tests three months earlier. The solution would have been to wait until the refinery maintenance crew unplugged the convection section and then run the low NO_x tests. Time constraints prevented KVB from rerunning the tests.

Another problem during the combined oil/gas firing tests was maintaining the same fuel split for each test. Fuel gas flow to the heater is automatically controlled by the TRC (temperature recorder and controller) while fuel oil delivery pressure is manually adjusted. The TRC will deliver the fuel gas required to maintain the crude outlet temperature between 611-619K (640-655°F). If the crude outlet temperature rises too much due to furnace changes, the oil/gas balance is upset. The TRC will reduce fuel gas pressure while fuel oil delivery pressure remains steady. To offset this change, the fuel oil delivery pressure must be reduced manually which lowers the thermal input contribution from the fuel oil. The TRC will then increase gas flow to the heater to replace lost Btu's from reduced fuel oil flow. This delicate balance between fuel oil and gas had to be watched closely from test to test.

As mentioned previously (Section 8.2), NO emissions varied considerably when plant fuel gas was burned. More plant fuel gas samples were needed to evaluate the changes in fuel composition on NO_x emissions. The ultimate means for evaluation would be an on-line continuous G/C analyzer.

SECTION 9.0

REFERENCES

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SECTION 10.0

CONVERSION FACTORS

SI Units to Metric or English Units

To Obtain	From	Multiply By
g/Mcal	ng/J	0.004186
10^6 Btu	GJ	0.948
Btu	gm cal	3.9685×10^{-3}
lb/10^6 Btu	ng/J	0.00233
ft	m	3.281
in.	cm	0.3937
ft^2	m^2	10.764
ft^3	m^3	35.314
lb	kg	2.205
Fahrenheit	Celsius	$t_F = 9/5(t_c) + 32$
Fahrenheit	Kelvin	$t_F = 1.8t_K - 460$
psig	Pa	$P_{psig} = (P_{pa})(1.450 \times 10^{-4}) - 14.7$
psia	Pa	$P_{psia} = (P_{pa})(1.450 \times 10^{-4})$
iwg (39.2 °F)	Pa	$P_{iwg} = (P_{pa})(4.014 \times 10^{-3})$
10^6 Btu/hr	MW	3.413
GJ/hr	MW	3.60

To Obtain ppm at 3% O_2 of	Multiply* Concentration in ng/J by
Natural Gas Fuel	
CO	3.23
HC	5.65
NO or NO_x	1.96
SO_2 or SO_x	1.41
Oil Fuel	
CO	2.93
HC	5.13
NO or NO_x	1.78
SO_2 or SO_x	1.28
Coal Fuel	
CO	2.69
HC	4.69
NO or NO_x	1.64
SO_2 or SO_x	1.18

*These conversions depend on fuel composition.
The values given are for typical fuels.

English and Metric Units to SI Units

To Obtain	From	Multiply By
ng/J	lb/10^6 Btu	430
ng/J	g/Mcal	239
GJ	10^6 Btu	1.055
m	ft	0.3048
cm	in.	2.54
m^2	ft^2	0.0929
m^3	ft^3	0.02832
kg	lb	0.4536
Celsius	Fahrenheit	$t_C = 5/9 (t_F - 32)$
Kelvin	Fahrenheit	$t_K = 5/9 (t_F - 32) + 273$
Pa	psig	$P_{pa} = (P_{psig} + 14.7)(6.895x10^3)$
Pa	psia	$P_{pa} = (P_{psia})(6.895x10^3)$
Pa	iwg (39.2 °F)	$P_{pa} = (P_{iwg})(249.1)$
MW	10^6 Btu/hr	0.293
MW	GJ/hr	0.278

To Obtain ng/J of	Multiply* Concentration in ppm @ 3% O_2 by
Natural Gas Fuel	
CO	0.310
HC	0.177
NO or NO_x (as NO_2)	0.510
SO_2 or SO_x	0.709
Oil Fuel	
CO	0.341
HC	0.195
NO or NO_x (as NO_2)	0.561
SO_2 or SO_x	0.780
Coal Fuel	
CO	0.372
HC	0.213
NO or NO_x (as NO_2)	0.611
SO_2 or SO_x	0.850

*These conversions depend on fuel composition. The values given are for typical fuels.

APPENDIX A-1.0

GASEOUS AND PARTICULATE EMISSIONS TEST METHODS AND INSTRUMENTATION

All emission measurement instrumentation was carried in a 9.8 m x 2.4 m (8 x 42 ft) mobile laboratory trailer. A plan view of the trailer is shown in Figure A-1. The gaseous species measurements were made with analyzers located in the trailer.

The emission measurement instrumentation in the trailer include the following:

TABLE A-1. EMISSION MEASUREMENT INSTRUMENTATION

Species	Manufacturer	Measurement Method	Model No.
Hydrocarbon	Beckman Instruments	Flame Ionization	402
Carbon Monoxide	Beckman Instruments	IR Spectrometer	865
Oxygen	Teledyne	Polarographic	326A
Carbon Dioxide	Beckman Instruments	IR Spectrometer	864
Nitrogen Oxides	Thermo Electron Co.	Chemiluminescent	10A
Particulates	Andersen Samplers, Inc.	EPA Method 5 Train	EPA
Sulfur Dioxide	DuPont Instruments	UV Spectrometer	400
Particle Sizing	Andersen Samplers, Inc.	Cascade Impactor	Mark III
Smoke Spot	Bacharach	ASTM 2156-65	RCC
Opacity		EPA Method 9	
Sulfur Oxides (SO_x)		Goksoyr-Ross	

A-1.1 GAS SAMPLING AND CONDITIONING SYSTEM

A flow schematic of the flue gas sampling and analyzing system is shown in Figure A-2. The sampling system uses three positive-displacement diaphragm pumps to continuously draw flue gas from the stack into the

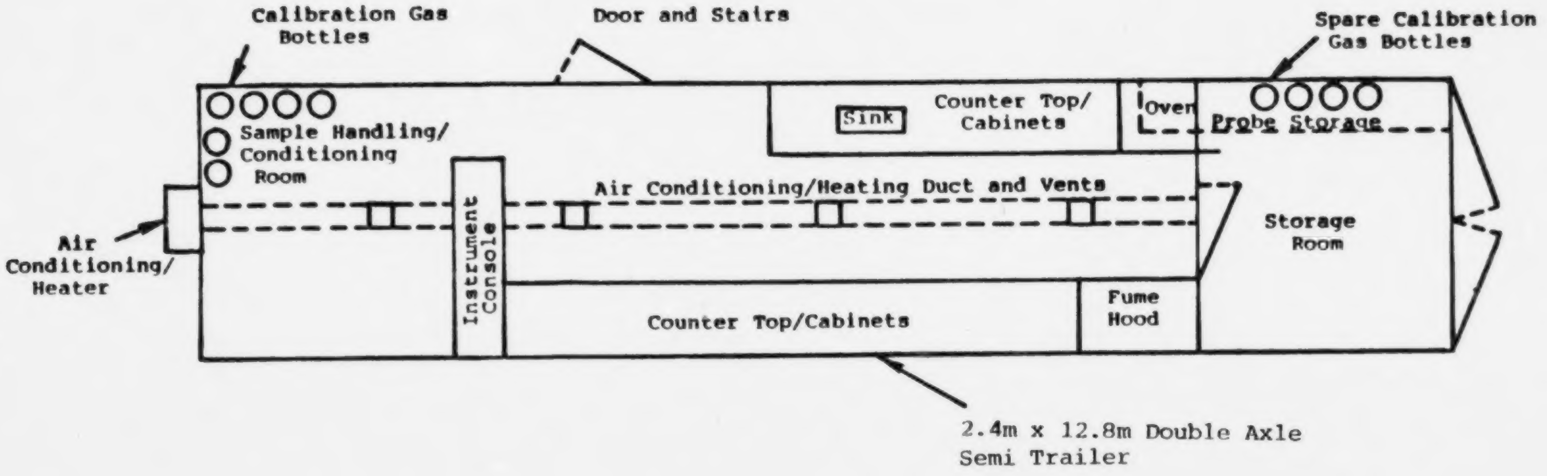
Calibration Gas Bottles
Door and Stairs
Spare Calibration Gas Bottles
Sample Handling/ Conditioning Room
Sink
Counter Top/ Cabinets
Oven
Probe Storage
Air Conditioning/Heating Duct and Vents
Air Conditioning/ Heater
Instrument Console
Storage Room
Counter Top/Cabinets
Fume Hood
2.4m x 12.8m Double Axle Semi Trailer

Figure A-1. Instrumentation trailer floor plan.

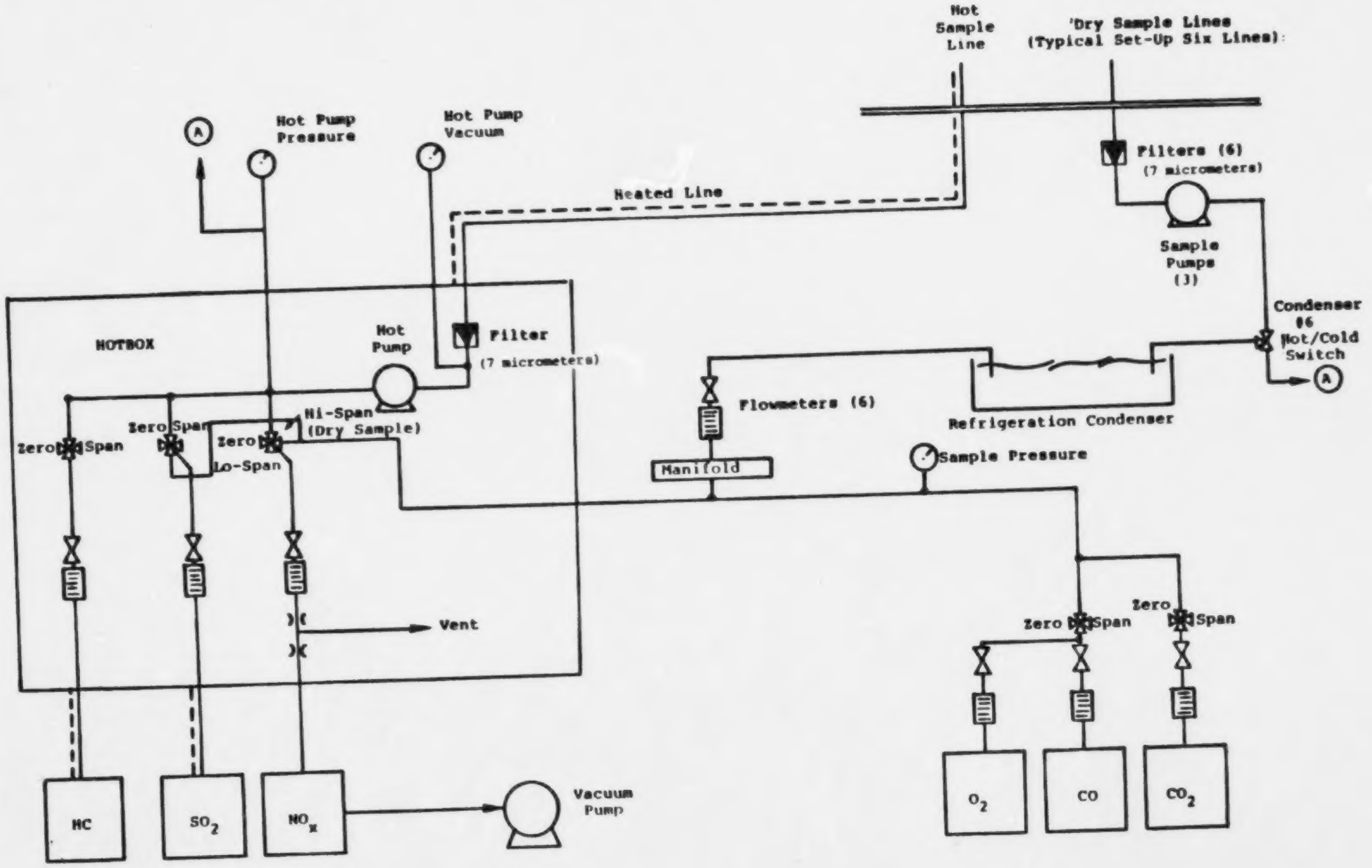
Hot Sample Line
'Dry Sample Lines (Typical Set-Up Six Lines):
Filters (6) (7 micrometers)
Sample Pumps (3)
Condenser #6 Hot/Cold Switch
A
Hot Pump Pressure
Hot Pump Vacuum
Heated Line
HOTBOX
Hot Pump
Filter (7 micrometers)
Hi-Span (Dry Sample)
Zero
Span
Lo-Span
Vent
Flowmeters (6)
Manifold
Refrigeration Condenser
Sample Pressure
HC
SO_2
NO_x
Vacuum Pump
O_2
CO
CO_2

Figure A-2. Flue gas sampling and analyzing system.

laboratory. The sample pumps pull from six unheated sample lines. Selector valves allow composites of up to six points to be sampled at one time. The probes are connected to the sample pumps with 0.95 cm (3/8") or 0.64 cm (1/4") nylon line. The positive displacement diaphragm sample pumps provide unheated sample gas to the refrigerated condenser (to reduce the dew point to 35°F), a rotameter with flow control valve, and to the O_2, NO, CO, and CO_2 instrumentation. Flow to the individual analyzers is measured and controlled with rotameters and flow control valves. Excess sample is vented to the atmosphere.

To obtain a representative sample for the analysis of NO_2, SO_2 and hydrocarbons, the sample must be kept above its dew point, since heavy hydrocarbons may be condensible, and SO_2 and NO_2 are quite soluble in water. For this reason, a separate electrically-heated sample line is used to bring the sample into the mobile laboratory for analysis. The sample line is 0.95 cm (3/8-inch) Teflon line, electrically traced and thermally insulated to maintain a sample temperature of up to 478 K (400°F). A heated diaphragm pump provides hot sample gas to the hydrocarbon, SO_2 and NO_x analyzers.

A-1.2 INSTRUMENTAL CONTINUOUS MEASUREMENTS

The laboratory trailer is equipped with analytical instruments to continuously measure concentrations of NO, NO_2, CO, CO_2, O_2, SO_2, and hydrocarbons. However, NO_2 and hydrocarbons were not measured during this program. All of the continuous monitoring instruments and sample handling system are mounted in the self-contained mobile laboratory. The entire system requires only connection to on-site water, power, and sampling lines to become fully operational. The instruments themselves are shock mounted on a metal console panel. The sample flow control measurement, and selection, together with instrument calibration are all performed from the console face. Three-pen recorders provide a continuous permanent record of the data taken. The sample gas is delivered to the analyzers at the proper condition and flow rate through the sampling and conditioning system described in the previous section. The sections below describe the analytical instrumentation.

A-1.2.1 Nitric Oxide (NO) and Total Nitrogen Oxides (NO_x)

Both the total nitrogen oxides (NO_x) and nitric oxide (NO) concentrations are measured from a sample gas obtained using a heated sample line at 394 K (250°F). In addition, the nitric oxide concentrations are measured sequentially from samples obtained using the unheated sample line that is connected to the same analyzer in the laboratory trailer. In the latter case, water is first removed from the sample gas by a refrigeration unit. The analytical instrument that is used for all of these measurements is the Thermo Electron Model 10A chemiluminescent gas analyzer.

For NO analyses, the sample gas is passed directly into the reaction chamber where a surplus of ozone is maintained. The reaction between the NO and the ozone produces light energy proportional to the NO concentration which is detected with a photomultiplier and converted to an electrical signal. Air for the ozonator is drawn from ambient through an air dryer and a 10-micrometer filter element.

The chemiluminescent reaction with ozone is specific to NO. To detect NO_2, a thermal converter has been designed to dissociate the NO_2 to NO by the bi-molecular reaction: $2\ NO_2 \rightarrow 2\ NO + O_2$. A model 700 thermal converter is used in conjunction with the chemiluminescent gas analyzer as shown in Figure A-3. The converter is a coil of resistance-heated stainless steel tubing whose purpose is to drive the NO_2/NO ratio to its chemical equilibrium value at the converter temperature and pressure. The unit is designed to operate at a temperature of 923 K (1200 °F) and pressure of .3 kPa (10 torr). For these conditions and typical stack gas O_2 concentrations, the equilibrium NO_2 concentration is 0.2 percent of the total NO_x concentration. Therefore, when a gas sample containing any NO_2 is passed through the converter, essentially all the NO_2 would be converted to NO. The resulting total NO is then measured using the chemiluminescent analyzer and the difference between the actual NO and the "total NO" would be the sample NO_2 concentration. The "total NO" is interpreted as NO_x.

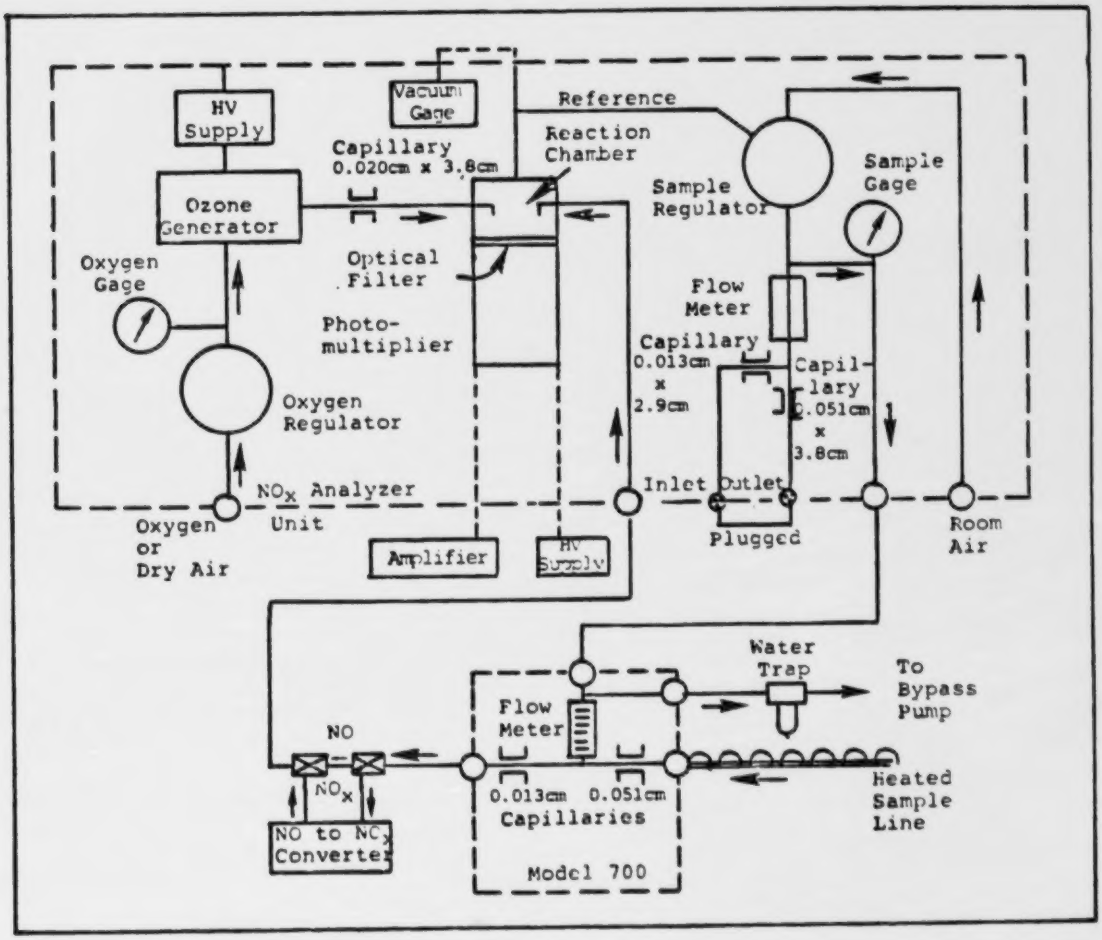
Vacuum Gage
HV Supply
Reference
Capillary 0.020cm x 3.8cm
Reaction Chamber
Sample Regulator
Sample Gage
Ozone Generator
Optical Filter
Oxygen Gage
Photo-multiplier
Flow Meter
Capillary 0.013cm x 2.9cm
Capil-lary 0.051cm x 3.8cm
Oxygen Regulator
NO_x Analyzer Unit
Inlet
Outlet
Plugged
Room Air
Oxygen or Dry Air
Amplifier
HV Supply
Water Trap
To Bypass Pump
Flow Meter
NO
NO_x
NO to NO_x Converter
0.013cm
0.051cm
Capillaries
Heated Sample Line
Model 700

Figure A-3. Schematic of NO_x/NO chemiluminescent analysis system.

NO_2 may react upon contact with H_2O (liquid phase) to form HNO_3 (nitric acid). Under field test conditions, the exhaust gas may contain significant H_2O (depending upon the process and the ambient meteorological conditions), and it is necessary to convert the NO_2 to NO before the H_2O is allowed to condense in the sampling system. By using the heated sample line and the Thermo Electron Model 700 heated NO_x module, NO_2 concentrations will effectively be measured. In reference to Figure A-3, the sample is maintained above the H_2O dew point up to and through the 127 μm (0.005 in.) capillary in the heated module. Downstream of this capillary, the flow network is maintained at 1.3 kPa (10 torr), where the partial pressure of the H_2O in the sample is sufficiently low to prevent any condensation at ambient temperature.

When using the heated system, NO, NO_2, and NO_x are measured on a wet basis. When not using the heated system, a condenser is placed upstream of the analyzer and NO is measured on a dry basis.

Specifications

Accuracy: 1% of full scale

Span stability: ± 1% of full scale in 24 hours

Zero stability: ± 1 ppm in 24 hours

Power requirements: 115 ± 10V, 60 Hz, 1000 watts

Response: 90% of full scale in 1 sec (NO_x mode);

0.7 sec (NO mode)

Output: 4-20 ma

Sensitivity: 0.5 ppm

Linearity: ± 1% of full scale

Vacuum detector operation

Range: 2.5, 10, 25, 100, 250, 1000, 2500, 10,000 ppm full scale

A-1.2.2 Carbon Monoxide and Carbon Dioxide (CO and CO_2)

Carbon monoxide and carbon dioxide concentrations are measured using Beckman Model 864 and 865 short-path-length nondispersive infrared analyzers (see Figure A-4). These instruments measure the differential in infrared energy absorbed from energy beams passed through a reference cell (containing a gas selected to have minimal absorption of infrared energy in the wavelength absorbed by the gas component of interest) and a sample cell through which the sample gas flows continuously. The differential absorption appears as a reading on a scale of 0% to 100% and is then related to the concentration of the species of interest by calibration curves supplied with the instrument. A linearizer is supplied with each analyzer to provide a linear output over the range of interest. The operating ranges for the CO analyzer are 0-100 and 0-2000 ppm, while the ranges for the CO_2 analyzer are 0-5% and 0-20%.

Specifications

Span stability: ± 1% of full scale in 24 hours

Zero stability: ± 1 ppm in 24 hours

Ambient temperature range: 273 to 322 K (32°F to 120°F)

Line voltage: 115 ± 15V rms

Response: 90% of full scale in 0.5 or 2.5 sec

Linearity: Linearizer board installed for one range

Precision: ± 1% of full scale

Output: 4-20 ma

A-1.2.3 Oxygen (O_2)

A Teledyne Model 326A oxygen analyzer is used to automatically and continuously measure the oxygen content of the flue gas sample. The analyzer utilizes a micro-fuel cell which is specific for oxygen, has an absolute zero, and produces a linear output from zero through 25 percent oxygen. The micro-fuel cell is a sealed electrochemical transducer with no electrolyte to change or electrodes to clean. Oxygen in the flue gas diffuses through a Teflon membrane and is reduced on the surface of the cathode. A corresponding

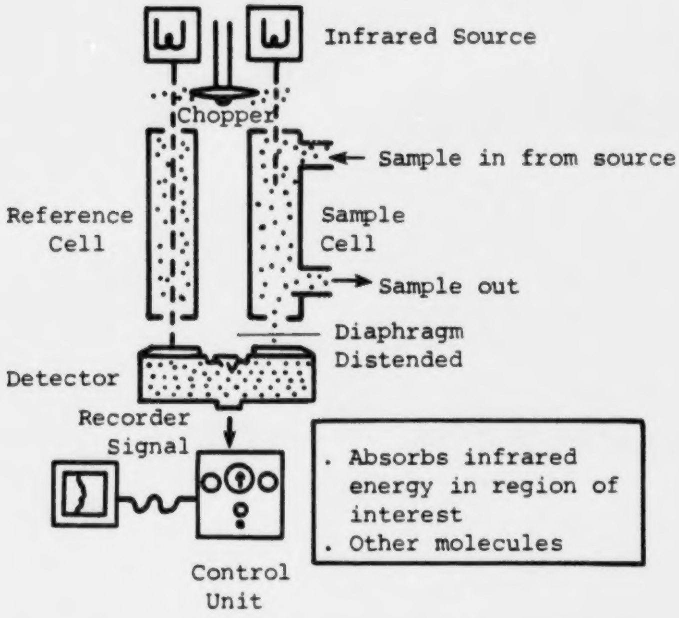
Infrared Source
Chopper
Sample in from source
Reference Cell
Sample Cell
Sample out
Diaphragm Distended
Detector
Recorder Signal
. Absorbs infrared energy in region of interest
. Other molecules
Control Unit

Figure A-4. Schematic of NDIR analyzer.

oxidation occurs at the anode internally and an electric current is produced that is proportional to the concentration of oxygen. This current is measured and conditioned by the instrument's electronic circuitry to give an output in percent O_2 by volume for operating ranges of 0% to 5%, 0% to 10%, and 0% to 25%.

Specifications

Precision: ± 1% of full scale

Response: 90% in less than 40 sec

Sensitivity: 1% of low range

Linearity: ± 1% of full scale

Ambient temperature range: 273 K to 325 K (32°F to 125°F)

Fuel cell life expectancy: 40,000% +-hrs

Power requirement: 115 VAC, 50-60 Hz, 100 watts

Output: 4-20 ma

A-1.2.4 Total Hydrocarbons (HC)

Hydrocarbon emissions are measured using a Beckman Model 402 high-temperature hydrocarbon analyzer. The analyzer utilizes the flame ionization method of detection which is a proven technique for a wide range of concentrations (0.1 to 120,000 ppm). A flow schematic of the analyzer is presented in Figure A-5. The sensor is a burner where a regulated flow of sample gas passes through a flame sustained by regulated flows of air and a premixed hydrogen/nitrogen fuel gas. Within the flame the hydrocarbon components of the sample stream undergo a complex ionization that produces electrons and positive ions. Polarized electrodes collect these ions, causing current to flow through electronic measuring circuitry. Current flow is proportional to the rate at which carbon atoms enter the burner.

The analysis occurs in a temperature-controlled oven. The sample is extracted from the stack with a stainless steel probe which has been thermally treated and purged to eliminate any hydrocarbons existing in the probe itself. An insulated heat-traced teflon line is used to transfer the sample

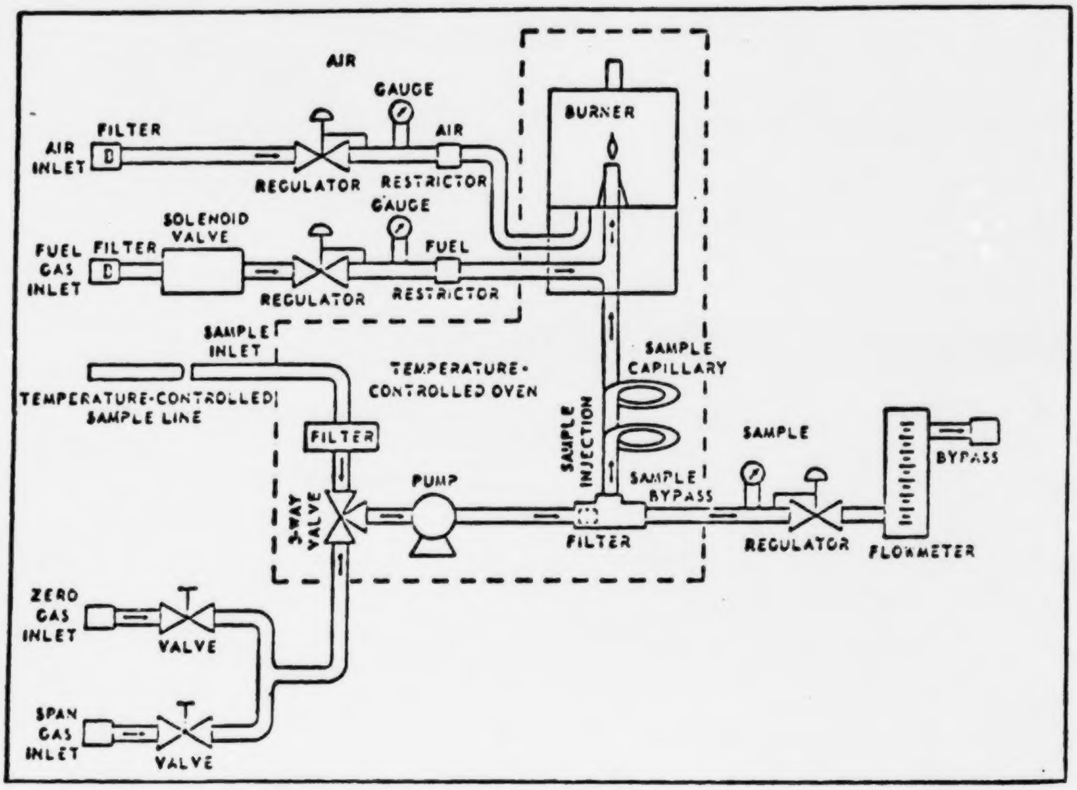
AIR
GAUGE
FILTER
AIR INLET
REGULATOR
AIR
RESTRICTOR
BURNER
SOLENOID VALVE
GAUGE
FUEL GAS INLET
FILTER
REGULATOR
FUEL
RESTRICTOR
SAMPLE INLET
TEMPERATURE-CONTROLLED OVEN
SAMPLE CAPILLARY
TEMPERATURE-CONTROLLED SAMPLE LINE
FILTER
SAMPLE INJECTION
SAMPLE
BYPASS
PUMP
SAMPLE BYPASS
3-WAY VALVE
FILTER
REGULATOR
FLOWMETER
ZERO GAS INLET
VALVE
SPAN GAS INLET
VALVE

Figure A-5. Flow schematic of hydrocarbon analyzer (FID).

to the analyzer. The entire heated network is maintained at a temperature sufficient to prevent condensation of heavier hydrocarbons.

The flame ionization detector is calibrated with methane, and the total hydrocarbon concentration is reported as the methane equivalent. FID's do not respond equally to all hydrocarbons but generally provide a measure of the carbon-hydrogen bonds present in the molecule. The FID does not detect pure carbon or hydrogen.

Specifications

Full-scale sensitivity: adjustable from 5 ppm CH_4 to 10% CH_4

Ranges: Range multiplier switch has 8 positions: X1, X5, X10, X50, X100, X500, X1000, and X5000. In addition, span control provides continuously variable adjustment within a dynamic range of 10:1

Response time: 90% full scale in 0.5 sec

Precision: ± 1% of full scale

Electronic stability: ± 1% of full scale per 24 hours with ambient temperature change of less than 5.6 K (10°F)

Reproducibility: ± 1% of full scale for successive identical samples

Analysis temperature: ambient

Ambient temperature: 273 K to 317 K (32°F to 100°F)

Output: 4-20 ma

Air requirements: 250 to 400 cc/min of clean, hydrocarbon-free air, supplied at 2.07×10^5 to 1.38×10^6 n/m^2 (30 to 200 psig)

Fuel gas requirements: 75 to 80 cc/min of fuel consisting of 100 percent hydrogen supplied at 2.07×10^5 to 1.38×10^6 n/m^2 (30 to 200 psig)

Electric power requirements: 120 V, 60 Hz

Automatic flame indication and fuel shut-off valve

A-1.2.5 Sulfur Dioxide (SO_2)

A Dupont Model 400 photometric analyzer is used for measuring SO_2. This analyzer measures the difference in absorption of two distinct wavelengths (ultraviolet) by the sample. The radiation from a selected light source passes through the sample and then into the photometer unit where the radiation is split by a semi-transparent mirror into two beams. One beam is directed to a phototube through a filter which removes all wavelengths except the "measuring" wavelength, which is strongly absorbed by the constituent in the sample. A second beam falls on a reference phototube, after passing through an optical filter which transmits only the "reference" wavelength. The latter is absorbed only weakly, or not at all, by the constituent in the sample cell. The phototubes translate these intensities to proportional electric currents in the amplifier. In the amplifier, full correction is made for the logarithmic relationships between the ratio of the intensities and concentration or thickness (in accordance with Beer's Law). The output is therefore linearly proportional, at all times, to the concentration and thickness of the sample. The instrument has a lower detection limit of 2 ppm and full scale ranges of 0-200 and 0-2000 ppm.

Specifications

Noise: Less than 1/4%

Drift: Less than 1% full scale in 24 hours

Accuracy: (± 1% of analyzer reading) + (± 1/4% of full scale range)

Sample cell: 304 stainless steel, quartz windows

Flow rate: 0.05 dm^3/s (6 cfh)

Light source: Either mercury vapor, tungsten, or "Osram" discharge type lamps

Power rating: 500 watts maximum, 115 V, 60 Hz

Reproducibility: 1/4% of scale

Electronic response: 90% in 1 sec

Sample temperature: 378 K (220°F)

Output: 4-20 ma d.c.

A-1.3 PARTICULATE MATTER TOTAL MASS CONCENTRATION

Particulate matter is collected by filtration and wet impingement in accordance with US-EPA Method No. 5. Nomograph techniques are utilized to select the proper nozzle size and to set the isokinetic flow rates.

Gas samples for particulate sampling can be taken from the same sample port as those for gas analysis and passed through the Joy Manufacturing Company Portable Effluent Sampler. This system, which meets the EPA design specifications for Test Method 5, Determination of Particulate Emissions from Stationary Sources (Federal Register, Volume 36, No. 27, page 24888, December 24, 1971, and revisions thereof) is used to perform both the initial velocity traverse and the particulate sample collection.

Dry particulates are collected in the heated case that may contain a cyclone to separate particles larger than 5 µm and a 110-mm glass-fiber filter to retain particles as small as 0.3 µm. Condensible particulates are collected in four Greenburg-Smith impingers immersed in a chilled water bath.

The sampling probe is positioned through an exhaust port and attached to the sampling box. The probe consists of a sampling nozzle, heated probe, gaseous probe, thermocouple, and pitot tube. The ball joint from the heated probe connects to the cyclone and glass filter holder assembly. These assemblies are positioned in the heated sampling box which is maintained at 394 K (250°F), in order to eliminate condensation. The sample then passes from the heated section to four Greenburg-Smith impingers immersed in an ice bath. Only the second impinger has the original tip, the other three have had the tip removed to decrease the pressure drop through them. The first and second impingers are filled with 150 milliliters of distilled/deionized water. The third impinger is left dry. The fourth impinger is filled with approximately 200 grams of indicating silica gel to remove entrained water. The use of silica gel assures that a dry sample is delivered to the meter box. After sampling, the spent silica gel is discarded and not used for any further analysis.

An umbilical cord connects the last impinger, the pitot tube, and the heating elements to the meter box which is located in a convenient place within 15 m of the sampling ports. The meter box contains a vacuum pump, regulating valves, instantaneous and integrating flow meters, pitot tube manometers, vacuum gauge, and electrical controls.

Particulate matter (solids and condensibles) is collected in three discrete portions by the sampling train: the probe and glassware upstream of the filter; the filter; and the wet impingers. The probe and glassware are brushed and rinsed with acetone; the matter is captured for gravimetric analysis. The probe and glassware are then rinsed with distilled water and the rinsings transferred to a second container for analysis. The filter is desiccated and analyzed gravimetrically. The combined impinger liquid is heated to drive off uncombined water and the residue retained for analysis. The particulate matter analysis is illustrated schematically in Figure A-6.

US EPA Method 5 considers the particulate matter captured in containers (1) and (3); the filter, probe brushing, and probe acetone rinse. As EPA source standards are based on solid particulates only, care is taken to differentiate between solid and the total (including condensible) particulates. The water wash is performed because KVB's test experience has shown that a significant amount of water-soluble material may sometimes be captured by the probe.

The dry sample volume is determined with a dry test meter at a measured temperature and pressure and then converted to standard conditions. The volume of condensed water in the impingers is measured in milliliters and the corresponding volume of water vapor is then computed at standard conditions. The dry sample volume and water vapor volume are then summed to give the total sample volume. The dry sample volume is used in the data reduction procedures.

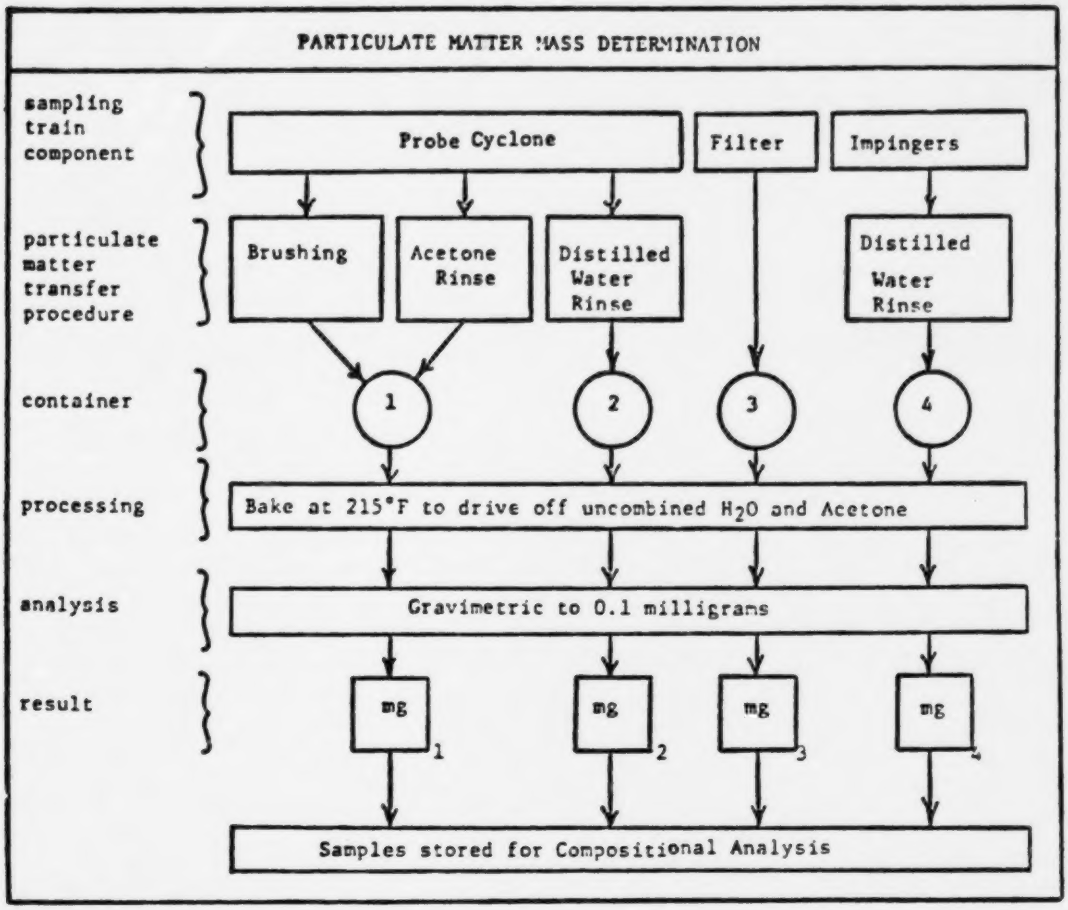
PARTICULATE MATTER MASS DETERMINATION
sampling train component
particulate matter transfer procedure
container
processing
analysis
result
Probe Cyclone
Filter
Impingers
Brushing
Acetone Rinse
Distilled Water Rinse
Distilled Water Rinse
1
2
3
4
Bake at 215°F to drive off uncombined H2O and Acetone
Gravimetric to 0.1 milligrams
mg 1
mg 2
mg 3
mg 4
Samples stored for Compositional Analysis

Figure A-6. Processing and analyzing particulate matter.

A point of interest is the method chosen to calculate particulate emissions in ng/J or lb/10^6 Btu from the experimental data. The particulate sampling train, properly operated, yields particulate mass per unit flue gas volume. Having measured g/m^3, it is necessary to establish the flue gas volume per unit heat input if emissions in ng/J are desired. The original Method 5 involved determining a velocity traverse of the stack, the cross-sectional area, the flue flow rate, and fuel heating value. A revised and more accurate method has been promulgated by the Environmental Protection Agency that utilizes a fuel analysis (carbon content, hydrogen content, high heating value, etc.) and the measured O_2 in the exhaust to calculate the gas volume generated in liberating 1.055 GJ (one million Btu's). The velocity traverse approach generally results in a 20 to 30 percent higher value and is believed to be less accurate.

A-1.4 SMOKE SPOT

On combustion equipment where smoke numbers normally are taken, such as oil-fired boilers, KVB, Inc. determines the smoke number using test procedures according to ASTM Designation: D 2156-65. The smoke number is determined at each combustion modification setting of the unit. Examples are baseline, minimum excess air, low load, etc., and whenever a particulate concentration is measured.

Smoke spots are obtained by pulling a fixed volume of flue gas through a fixed area of a standard filter paper. The color (or shade) of the spots that are produced is visually matched with a standard scale. The result is a "Smoke Number" which is used to characterize the density of smoke in the flue gas.

The sampling device is a hand pump similar to the one shown in Figure A-7 . It is a commercially available item that can pass 36,900 ± 1650 cu cm of gas at 289K and 1 atmosphere pressure through an enclosed filter paper for each 6.5 sq cm effective surface area of the filter paper.

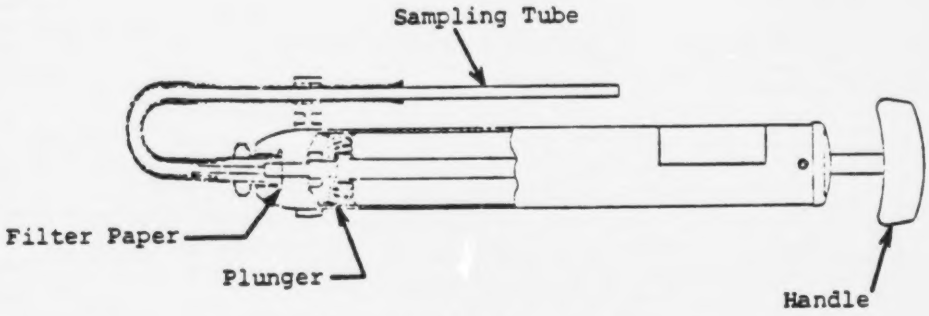

Figure A-7. Field-service-type smoke tester.

The smoke spot sampler is provided with a motor-driven actuator to ensure a constant sampling rate independent of variations in stroke rate that can occur when the sampler is operated manually.

The smoke scale required consists of a series of ten spots numbered consecutively from 0 to 9, and ranging in equal photometric steps from white through neutral shades of gray to black. The spots are imprinted or otherwise processed on white paper or plastic stock having an absolute surface reflectance of between 82.5 and 87.5%, determined photometrically. The smoke scale spot number is defined as the reduction (due to smoke) in the amount of light reflected by a soiled spot on the filter divided by 10.

Thus the first spot, which is the color of the unimprinted scale, is No. 0. In this case there is no reduction in reflected incident light directed on the spot. The last spot, however, is very dark, reflecting only 10% of the incident light directed thereon. The reduction in reflected incident light is 90%, and this spot is identified as No. 9. Intermediate spot numbers are similarly established. Limits of permissible reflectance variation of any smoke scale spot will not exceed ± 3% relative reflectance.

The test filter paper is made from white filter paper stock having absolute surface reflectance of 82.5 to 87.5%, as determined by photometric measurement. When making this reflectance measurement, the filter paper is backed by a white surface having absolute surface reflectance of not less than 75%.

When clean air at standard conditions is drawn through clean filter paper at a flow rate of 47.6 cu cm per sec per sq cm effective surface area of the filter paper, the pressure drop across the filter paper falls between the limits of 1.7 and 8.5 kPa (1.3 and 6.4 cm of mercury).

The sampling procedure is exactly that specified in D 2156. A clean, dry, sampling pump is used. It is warmed to room temperature to prevent condensation on the filter paper. When taking smoke measurements in the flue pipe, the intake end of the sampling probe is placed at the center line of the flue. When drawing the sample, the pressure in the flue gas stream and the sampler is allowed to equalize after each stroke.

The smoke density is reported on the Mobile Lab Data Sheet as the Smoke Spot Number on the standard scale most closely corresponding to test spot. Differences between two standard Smoke Spot Numbers are interpolated to the nearest half number. Smoke Spot Numbers higher than 9 are reported as "Greater than No. 9."

This procedure is deemed to be reproducible to within ± 1/2 of a Smoke Spot Number under normal conditions where no oily stain is deposited on the disk.

KVB's field experience with industrial boilers has been that the human factor involved in the interpretation of the smoke spot by an experienced observer does not cause a significant lack of precision.

A-1.5 OPACITY

Opacity readings are taken by a field crew member who is a certificated graduate of a U.S. Environmental Protection Agency approved "Smoke School". Observations are made at the same time that particulate measurements are made and as often in addition as deemed necessary to gather the maximum amount of information. The procedures set forth in EPA Method 9, "Visual Determinations of the Opacity of Emissions for Stationary Sources" are followed.

Observations are made and recorded at 15 second intervals while particulate concentration is being measured and after the unit has stabilized at other times. Before beginning observations, the observer determines that the feedstock or fuel is the same as that from which the sample was taken for the fuel analysis.

Before beginning opacity observations, the observer makes arrangements with the combustion unit operator to obtain the necessary process data for the standard KVB Control Room Data Sheet. The control room data are recorded for the entire period of observations, as is customarily done by KVB during an emissions test. The process unit data that are obtained include:

a. Production rates
    1. maximum rated capacity
    2. actual operating rate during test
b. Control device data
    1. recent maintenance history
    2. cleaning mechanism and cycle information

The observer requests the appropriate plant personnel to briefly review and comment on the opacity measurements and process data and the observer comments on:

a. the basis for choosing the observation periods used.

b. why it is believed the periods chosen constitute periods of greatest opacity.

c. why the observations span a time period sufficient to characterize the opacity.

Consideration is given to postponing the EPA Method 5 particulate tests during periods of cloudy or rainy weather because of the inability of the observer to monitor the smoke.

A-1.5.1 Sulfur Oxides (SO_x)

Goksoyr-Ross Method--Wet Chemical Method

The Goksoyr-Ross Controlled Condensate (G/R) method is used for the wet chemical SO_2/SO_3 determination. It is a desirable method because of its simplicity and clean separation of particulate matter, SO_2 and H_2SO_4 (SO_3). This procedure is based on the separation of H_2SO_4 (SO_3) from SO_2 by cooling the gas stream below the dew point of H_2SO_4 but above the H_2O dew point. Figure A-8 illustrates schematically the G/R test system.

Particulate matter is first removed from exhaust gas stream by means of a quartz glass filter placed in the heated glass filter holder. Tissue-quartz filters are recommended because of their proven inertness to H_2SO_4. The filter system is heated by a heating tape so that the gas out temperature of 533 K (500°F) is maintained. This temperature is imperative to ensure that none of the H_2SO_4 will condense in the filter holder or on the filter.

The condensation coil where the H_2SO_4 is collected is cooled by water which is maintained at 333 K (140°F) by a heater/recirculator. This temperature is adequate to reduce the exhaust gas to below the dew point of H_2SO_4.

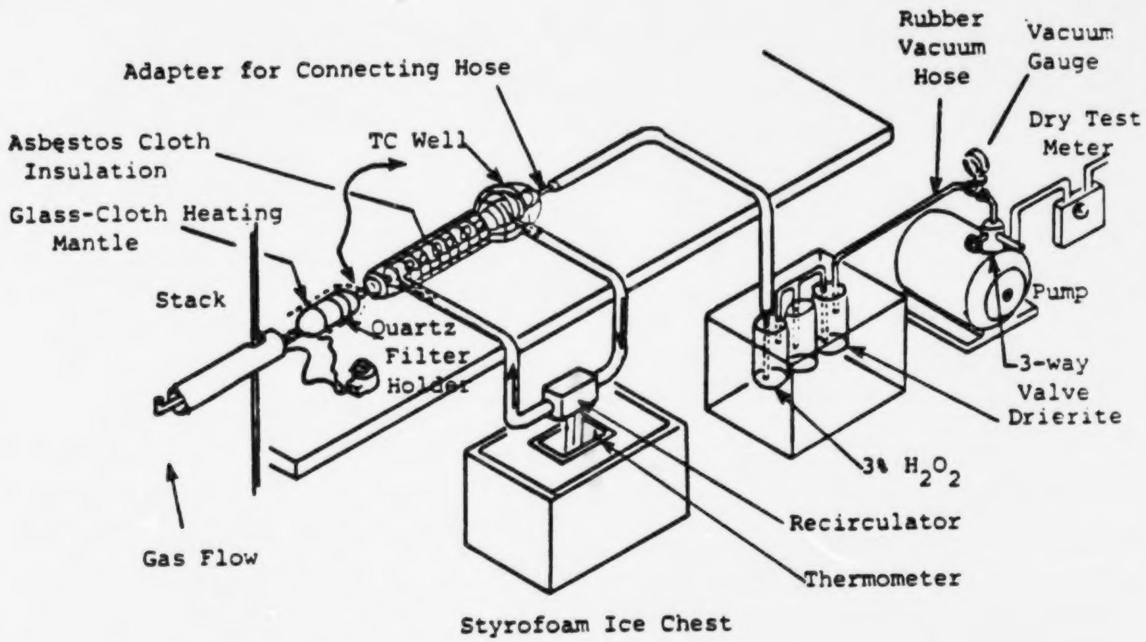
Adapter for Connecting Hose
Rubber Vacuum Hose
Vacuum Gauge
Dry Test Meter
Asbestos Cloth Insulation
TC Well
Glass-Cloth Heating Mantle
Stack
Quartz Filter Holder
Pump
3-way Valve
Drierite
3% H_2O_2
Recirculator
Thermometer
Gas Flow
Styrofoam Ice Chest

Figure A-8. Schematic of Goksoyr-Ross controlled condensation system (CCS).

Three impingers are shown in Figure A-8. The first impinger is filled with 3 percent H_2O_2 to absorb SO_2. The second impinger is to remove carryover moisture and the third contains Drierite and a thermometer to measure the exhaust gas temperature to the dry gas meter and pump. The sampling rate is 0.04 dm^3/s (0.08 cfm).

A-1.5.2 Analysis Procedure

For both SO_2 and H_2SO_4 determination, the analytical procedure is identical. The H_2SO_4 sample is washed from the back part of the filter holder and the coil using a 5 percent isopropyl alcohol solution. The sample from the first impinger which is assumed to be absorbed and reacted SO_2 in the form of H_2SO_4 is recovered with distilled water washing. The amount of H_2SO_4 in the condensate from the coil and from the H_2O_2 impinger is measured by H+ titration. Bromphenol Blue is used with NaOH as the titrant.

A-1.6 PARTICLE SIZE DISTRIBUTION

An Anderson Mark III in stack particle fractionating sampler was used for the particle size distribution tests (Figure A-9).

A-1.6.1 Design

The Anderson stack sampling has been designed to operate with the EPA Method 5 train. The stack head consists of a stainless steel case and 1/2" (13 cm) NPT female pipe fittings. The stack sampler contains nine jet plates, each having a pattern of precision drilled orifices. Special collection substrates, (e.g., glass fiber, aluminum foil, etc.) placed on the jet/collection plates, permit lighter tare weights for gravimetric analyses and a variety of collection materials for chemical analysis. The sampler may be used with or without the collection substrate. The nine plates are separated by 2.5 millimeter stainless steel spacers. The jets on each plate are arranged in modified concentric circles which are offset on each succeeding plate. The size of the orifices is the same on a given plate, but smaller for each succeeding downstream plate. Therefore, as the sample is drawn through the sampler at a constant flow rate, the jets of air flowing through any

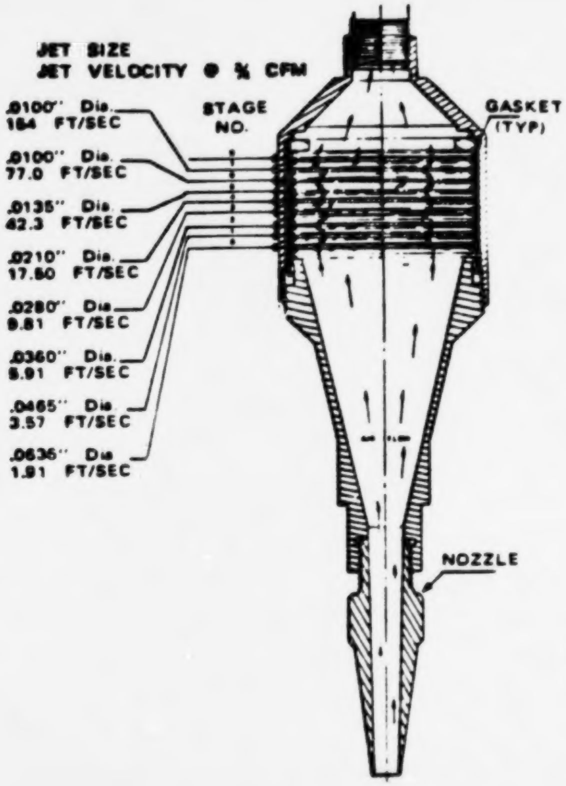
JET SIZE
JET VELOCITY @ ½ CFM
.0100" Dia. 184 FT/SEC
.0100" Dia. 77.0 FT/SEC
.0135" Dia. 42.3 FT/SEC
.0210" Dia. 17.80 FT/SEC
.0280" Dia. 9.81 FT/SEC
.0360" Dia. 5.91 FT/SEC
.0465" Dia. 3.57 FT/SEC
.0635" Dia 1.91 FT/SEC
STAGE NO.
GASKET (TYP)
NOZZLE

Figure A-9.
Impactor Head

particular plate direct the particles toward the collection substrate on the downstream plate directly below the circles of jets on the plate above. Since the jet diameters decrease from plate to plate, the velocities increase such that whenever the velocity imparted to a particle is sufficiently great, its inertia will overcome the aerodynamic drop of the turning air stream and the particle will be impacted on the collection substrate. Otherwise, the particle remains in the air stream and proceeds to the next plate.

Since the particle deposit areas are directly below the jets, seven of the plates act as both a jet stage and a collection plate. Thus, No. 0 plate is only a jet stage and No. 8 plate is only a collection plate.

The stack sampler is designed to operate at 0.35 dm^3/s (0.75 acfm) or less. An optimum flow rate is around 0.24 dm^3/s (0.5 acfm).

A-1.6.2 Operation

An EPA Method 5 train is used to draw a sample of the flue gas through the impactor. All particles entrained in the air stream are inertially impacted on the preweighed collection surfaces. The size ranges of particles deposited is from >10 microns with preseparator to <0.4 microns on the last stage. It is recommended that the preseparator be used to remove the larger particles when conditions warrant and it is necessary to use a backup filter always to ensure total collection. The collection media used during the test series were glass fiber filters. The filters were preconditioned for weighing before and after a sampling cycle in a desiccator.

Normal sampling periods vary from a few minutes to several hours depending on the grain loading situation. Ten milligrams of particulate matter on any one plate represents an approximate upper limit because of re-entrainment problems. Overloading the sampler can be detected easily by visual inspection and occurs more often during the first test at an unfamiliar stack. After the sampling cycle has been completed, the sampler is disassembled. After the desiccating of the collection media, weighing is performed to determine the net particulate accumulations.

A-1.6.3 Data Presentation

To determine the concentration of particulates for any size range, first determine the percentage of total particulates for each stage. Then the cumulative percentage is determined beginning with the last stage of the impactor. By plotting the effective cutoff diameter (ECD) and the cumulative percent on logarithmic probability graph paper, then the particle concentration by weight for any specific size can be determined.

APPENDIX B

FIELD TEST DATA SUMMARY FOR A PILOT-SCALE PROCESS HEATER

APPENDIX B
EMISSIONS SUMMARY: REFINERY PROCESS HEATER, 10/82

TEST #	FUEL& NG-FG/AG/ NO.6	PROC. RATE M3/H	HEAT INPUT MW	O2 %	NO PPM*	NO NG/J	CO PPM*	CO2 %	STACK T K	STACK T F	HTR EFF	SEC AIR REG. %OPEN	FURN. PRESS. -IWC	STAGE HT. M	STAGE HT. FT	LANC DIA IN	BRN EQUI RATI	COMMENTS
10/5-1	0/100/0	62.1	11.9	6.6	153	78	3	9.4	658	725	69.8	50	-	--	--	--	1.33	AS FOUND,VIEWPORTS-AS FOUND,SEC AIR VARIED +/- 25%
10/6-1	0/100/0	75.1	13.7	3.5	128	65	4	11.4	669	744	72.1	50	-	--	--	--	1.18	AS FOUND,VIEWPORTS-SOME PARTIALLY CLOSED,SEC AIR VARIED +/- 25%
10/6-1A	0/100/0	75.1	13.7	3.8	126	64	4	10.9	672	751	--	50	-	--	--	--	--	AS FOUND,VIEWPORTS-SOME PARTIALLY CLOSED,SEC AIR VARIED +/- 25%
10/6-1B	0/100/0	75.1	13.7	3.6	127	64	5	11.6	671	748	--	50	-	--	--	--	--	AS FOUND,VIEWPORTS-SOME PARTIALLY CLOSED,SEC AIR VARIED +/- 25%
10/6-1C	0/100/0	76.1	13.7	3.5	131	66	4	11.4	667	741	--	50	-	--	--	--	--	AS FOUND,VIEWPORTS-SOME PARTIALLY CLOSED,SEC AIR VARIED +/- 25%
10/6-1D	0/100/0	75.1	13.7	3.2	125	64	3	12.1	667	742	--	50	-	--	--	--	--	AS FOUND,VIEWPORTS-SOME PARTIALLY CLOSED,SEC AIR VARIED +/- 25%
10/6-1E	0/100/0	76.1	13.7	3.6	132	67	2	10.6	667	741	--	50	-	--	--	--	--	AS FOUND,VIEWPORTS-SOME PARTIALLY CLOSED,SEC AIR VARIED +/- 25%
10/7-1	0/100/0	75.1	13.4	3.9	124	63	3	11.2	669	744	72	50	.27	--	--	--	1.2	AS FOUND,VIEWPORTS-SOME TOTALLY CLOSED,SEC AIR VARIED +/- 25%
10/7-1A	0/100/0	76.1	13.4	3.7	121	62	7	11.4	669	744	--	50	.27	--	--	--	--	AS FOUND,VIEWPORTS-SOME TOTALLY CLOSED,SEC AIR VARIED +/- 25%
10/7-1B	0/100/0	76.1	13.4	3.7	123	62	7	11.1	669	744	--	50	.27	--	--	--	--	AS FOUND,VIEWPORTS-SOME TOTALLY CLOSED,SEC AIR VARIED +/- 25%
10/7-1C	0/100/0	76.1	13.4	3.9	125	64	4	11.2	669	744	--	50	.27	--	--	--	--	AS FOUND,VIEWPORTS-SOME TOTALLY CLOSED,SEC AIR VARIED +/- 25%
10/7-1D	0/100/0	76.1	13.4	4	127	64	5	11	669	744	--	50	.27	--	--	--	--	AS FOUND,VIEWPORTS-SOME TOTALLY CLOSED,SEC AIR VARIED +/- 25%
10/7-1E	0/100/0	76.1	13.4	3.8	127	64	5	11.1	668	743	--	50	.27	--	--	--	--	AS FOUND,VIEWPORTS-SOME TOTALLY CLOSED,SEC AIR VARIED +/- 25%
10/8-1	0/100/0	76.1	14.2	4	131	67	7	11.2	674	753	71.9	50	.3	--	--	--	1.2	BASELINE,VIEWPORTS-SOME TOTALLY OPEN ,SEC AIR VARIED +/- 25%
10/8-2	0/100/0	76.1	14.2	4.4	105	54	5	10.8	678	760	71.2	50	.17	.12	.4	--	.86	STAGED,4" PORTS
10/8-3	0/100/0	76.1	14.2	3.9	99	51	2	11.2	674	753	71.9	50	.18	.12	.4	--	.81	STAGED,4" PORTS
10/8-4	0/100/0	76.1	14.2	4.1	84	43	4	11.2	672	749	72	33	.23	.12	.4	--	.73	STAGED,4" PORTS
10/8-5	0/100/0	76.1	14.2	3.9	69	35	7	11.8	671	747	72.7	10	.27	.12	.4	--	.72	STAGED,4" PORTS
10/12-1	9/91/0	76.1	14.2	3.8	146	74	4	11.7	663	734	72.9	50	.34	--	--	--	1.19	BASELINE, VIEWPORTS-CLOSED FOR REMAINING TESTS,SEC AIR VARIED +/- 25%
10/12-2	9/91/0	76.1	14.2	4.5	117	60	4	11.6	671	748	72.5	50	.21	.12	.4	--	.81	STAGED,4" PORTS
10/12-3	9/91/0	76.1	14.2	3.2	125	64	6	11.4	661	729	72.7	50	.35	1.2	4	1.25	1.1	STAGED
10/13-1	0/100/0	76.1	12.9	3.8	128	65	5	11.6	671	747	72.4	10	.6	1.2	4	1.25	1.1	STAGED
10/13-2	0/100/0	76.1	12.9	3.4	117	60	4	11.3	669	745	72.2	33	.5	1.2	4	1.25	1.09	STAGED
10/13-3	0/100/0	76.1	12.9	3.7	131	67	3	10.4	667	741	71.2	50	.44	1.2	4	1.25	1.11	STAGED
10/13-4	0/100/0	76.1	12.9	3.6	138	70	6	12.3	661	730	73.6	50	.35	--	--	--	1.18	BASELINE
10/14-1	9/91/0	76.1	14.2	2.6	91	46	6	11.5	648	707	73.4	50	.2	.12	.4	--	.73	STAGED,4" PORTS
10/14-2	9/91/0	76.1	14.2	4.1	116	59	7	10.9	656	721	72.4	50	.23	.12	.4	--	.77	STAGED,4" PORTS
10/14-3	9/91/0	76.1	14.6	4.1	152	78	7	11.3	664	735	72.5	50	.5	--	--	--	1.21	BASELINE
10/15-1	8/92/0	76.1	15	4.9	130	66	5	10.7	674	754	69.4	50	.55	--	--	--	1.25	BASELINE
10/15-2	8/92/0	76.1	15	3.5	107	55	4	11.3	673	752	70.3	33	.67	--	--	--	1.18	BASELINE
10/15-3	9/91/0	76.1	14.7	3.5	76	39	5	11.2	673	752	70.2	33	.27	.12	.4	--	.72	STAGED,4" PORTS
10/15-4	9/91/0	76.1	14.7	1.9	55	28	6	11.9	646	703	72.3	33	.22	.12	.4	--	.64	STAGED,4" PORTS,LEA
10/15-5	9/91/0	76.1	14.7	4.6	91	46	5	10.6	663	734	69.8	33	.35	.12	.4	--	.71	STAGED,4" PORTS
10/18-1	0/100/0	76.1	13.3	3.7	127	65	4	11.3	657	722	73.3	50	.4	--	--	--	1.19	BASELINE
10/18-1R	0/100/0	76.1	13	4	134	68	6	11.2	654	717	73.3	50	.38	--	--	--	1.2	BASELINE
10/18-2	0/100/0	76.1	13	3.6	120	61	6	11.4	654	718	73.5	50	.28	1.2	4	3	.87	STAGED, LANCE TIP TOWARD BURNER AXIS
10/18-3	0/100/0	76.1	13	3.9	119	61	6	11.2	657	723	73.1	33	.4	1.2	4	3	.83	STAGED, LANCE TIP TOWARD BURNER AXIS
10/18-4	0/100/0	76.1	13	3.4	99	51	6	11.3	655	720	73.3	10	.55	1.2	4	3	.74	STAGED, LANCE TIP TOWARD BURNER AXIS
10/19-1	0/100/0	69.6	12.8	4.4	138	70	5	11.1	654	717	73.2	50	.35	--	--	--	1.22	BASELINE
10/19-2	0/100/0	69.6	12.8	3.7	120	61	5	11.2	649	709	73.5	50	.25	1.2	4	3	.89	STAGED, LANCE TIP TOWARD HEATER AXIS
10/19-3	0/100/0	69.6	12.8	3.9	107	55	5	11	651	712	73.2	33	.37	1.2	4	3	.84	STAGED, LANCE TIP TOWARD HEATER AXIS
10/19-4	0/100/0	69.6	12.8	3.8	107	55	5	10.7	652	713	72.8	10	.48	1.2	4	3	.78	STAGED, LANCE TIP TOWARD HEATER AXIS
10/19-5	0/100/0	69.6	12.8	4	148	76	5	10.7	651	712	72.8	50	-	--	--	--	1.2	BASELINE
10/20-1	0/100/0	69.8	12.7	4.1	137	70	5	10.9	650	710	75	50	.41	--	--	--	1.21	BASELINE
10/20-2	0/100/0	69.8	12.7	3.5	128	65	5	11.1	641	694	75.6	50	.3	.61	2	3	.85	STAGED, LANCE TIP TOWARD BURNER AXIS
10/20-3	0/100/0	69.8	12.7	4	122	62	5	11.2	648	707	75.4	33	.41	.61	2	3	.82	STAGED, LANCE TIP TOWARD BURNER AXIS
10/20-4	0/100/0	69.8	12.7	3.6	106	54	5	10.9	647	704	75.1	10	.53	.61	2	3	.75	STAGED, LANCE TIP TOWARD BURNER AXIS
10/20-5	0/100/0	69.8	12.7	3.9	137	70	5	10.7	647	705	74.9	50	-	--	--	--	1.2	BASELINE

APPENDIX B
EMISSIONS SUMMARY: REFINERY PROCESS HEATER, 10/82 (CONTINUED)

TEST #	FUEL% NG-FG/AG/ NO.6	PROC. RATE M3/H	HEAT INPUT MW	O2 %	NO PPM*	NO NG/J	CO PPM*	CO2 %	STACK T K	STACK T F	HTR EFF	SEC AIR REG. %OPEN	FURN. PRESS. -IWC	STAGE HT. M	STAGE HT. FT	LANC DIA IN	BRN EQUI RATI	COMMENTS
10/21-1	0/100/0	75.9	12.9	1.8	123	63	6	12	648	706	75.9	50	.41	--	--	--	1.09	BASELINE
10/21-2	0/100/0	75.9	12.9	3.8	97	50	5	11.5	647	706	75.7	50	.25	.12	.4	--	.69	STAGED,4" PORTS
10/21-3	0/100/0	76.3	12.7	1.4	62	32	5	12	648	706	76.2	50	.17	.12	.4	--	.65	STAGED,4" PORTS,LEA
10/21-4	0/100/0	76.3	13.5	5.8	125	64	4	10.2	674	754	73	50	.33	.12	.4	--	.73	STAGED,4" PORTS
10/21-5	0/100/0	76.3	12.4	3.8	69	35	5	11	660	728	74.6	10	.38	.12	.4	--	.55	STAGED,4" PORTS
10/21-6	0/100/0	76.5	12.7	1.9	59	30	5	11.9	641	693	76.3	10	-	.12	.4	--	.58	STAGED,4" PORTS,LEA
10/21-5R	0/100/0	76.6	12.7	3.6	72	37	4	11.5	660	728	75.1	10	.25	.12	.4	--	.55	STAGED,4" PORTS
10/21-7	0/100/0	76.3	13.2	5.5	92	47	4	10.5	668	743	73.7	10	.47	.12	.4	--	.6	STAGED,4" PORTS
10/21-8	0/100/0	76.3	13.2	3.3	108	55	4	11.6	651	712	75.6	10	.65	--	--	--	1.17	BASELINE
10/25-1	0/100/0	52.7	9.8	8.1	127	65	1	6.9	638	689	67.3	50	.36	--	--	--	1.41	STAGED,4" PORTS
10/25-2	0/100/0	52.7	8.5	5.7	113	58	19	10.2	609	636	74.9	50	.08	.12	.4	--	.85	STAGED,4" PORTS
10/25-3	0/100/0	52.7	8.5	2.5	89	45	8	11.7	590	602	77.3	50	.04	.12	.4	--	.82	STAGED,4" PORTS
10/25-4	0/100/0	52.7	8.5	3.9	92	47	7	11	594	609	76.5	33	.1	.12	.4	--	.71	STAGED,4" PORTS
10/25-5	0/100/0	52.7	8.5	2	67	34	5	12	585	593	77.7	33	.08	.12	.4	--	.67	STAGED,4" PORTS
10/25-6	0/100/0	52.7	8.5	6.7	122	62	1	9.8	617	650	74	33	.16	.12	.4	--	.72	STAGED,4" PORTS
10/25-7	0/100/0	52.7	8.5	4.1	79	40	4	10.8	596	613	76.2	10	.14	.12	.4	--	.63	STAGED,4" PORTS
10/25-8	0/100/0	52.7	8.5	2.3	66	34	10	10.8	583	590	76.8	10	.12	.12	.4	--	.58	STAGED,4" PORTS
10/25-7R	0/100/0	52.7	8.5	4.4	89	45	9	10.8	596	613	76.2	10	-	.12	.4	--	.67	STAGED,4" PORTS
10/25-9	0/100/0	52.7	8.5	5.9	110	56	4	10.1	607	632	74.9	10	.18	.12	.4	--	.67	STAGED,4" PORTS
10/25-10	0/100/0	52.7	8.5	3.7	138	70	4	11.3	598	616	76.6	10	.24	--	--	--	1.19	CAPS ON PORTS
10/25-11	0/100/0	52.7	8.5	4.1	152	78	5	11.1	594	610	76.6	33	-	--	--	--	1.22	CAPS ON PORTS
10/26-1	100/0/0	75.9	12.9	1.8	178	91	2	12	647	705	75.9	50	-	--	--	--	1.09	AS FOUND, CAPS ON PORTS
10/26-2	100/0/0	75.9	12.9	.8	90	--	21	--	666	739	76.9	50	-	.12	.4	--	--	STAGED,4" PORTS,CO LIMIT
10/26-3	100/0/0	75.9	12.9	.8	58	--	24	--	678	761	76.5	33	-	.12	.4	--	--	STAGED,4" PORTS,CO LIMIT
10/26-4	100/0/0	75.9	12.9	.8	90	--	21	--	678	761	76.3	10	-	.12	.4	--	--	STAGED,4" PORTS,CO LIMIT
10/26-5	100/0/0	75.9	12.9	2	90	46	0	12	641	694	76.4	10	.3	.12	.4	--	.55	STAGED,4" PORTS
10/26-6	100/0/0	75.9	12.9	3.6	124	64	2	11	656	720	74.8	10	.38	.12	.4	--	.56	STAGED,4" PORTS
10/26-7	100/0/0	75.9	12.9	5.8	157	81	6	10.1	669	745	73.3	10	.5	.12	.4	--	.58	STAGED,4" PORTS
10/26-1R	100/0/0	75.9	12.9	2.5	200	104	15	10.8	652	713	74.7	50	-	--	--	--	1.12	AS FOUND, CAPS ON PORTS
10/27-1	28/72/0	84.5	15.7	3.1	133	68	4	11	665	737	75.4	50	.45	--	--	--	1.16	AS FOUND, CAPS ON PORTS
10/27-2	28/72/0	84.5	15.7	3.4	91	46	2	10.9	664	735	75.3	50	.22	.12	.4	--	.78	STAGED,4" PORTS
10/27-3	28/72/0	84.5	15.7	1.6	77	40	8	11.5	665	719	76.3	50	.14	.12	.4	--	.75	STAGED,4" PORTS
10/27-4	28/72/0	84.5	15.7	5.1	123	63	5	10.2	659	727	74.4	50	.28	.12	.4	--	.82	STAGED,4" PORTS
10/27-5	29/71/0	84.5	15.4	3.1	88	45	6	11.7	666	738	76	33	.05	.12	.4	--	.72	STAGED,4" PORTS
10/27-6	26/74/0	84.5	14.9	1.7	67	34	5	12.1	657	722	76.7	33	.23	.12	.4	--	.68	STAGED,4" PORTS
10/27-7	26/74/0	84.5	14.9	5.4	119	61	6	10.5	658	725	75	33	.35	.12	.4	--	.75	STAGED,4" PORTS
10/27-8	26/74/0	84.5	14.9	3.6	82	42	8	11.1	654	717	75.9	10	.35	.12	.4	--	.67	STAGED,4" PORTS
10/27-9	26/74/0	84.5	14.9	1.9	64	33	8	12	670	746	76.1	10	.43	.12	.4	--	.52	STAGED,4" PORTS
10/27-10	28/72/0	84.5	15.4	5.2	96	49	7	10.2	682	768	73.6	10	.55	.12	.4	--	.64	STAGED,4" PORTS
10/27-11	29/71/0	84.5	15.4	1.7	116	59	0	11.7	--	--	--	50	-	--	--	--	1.08	

*ppmv, dry, corrected to 3% O_2

NO on a mass basis is in terms of NO_2

APPENDIX B

EMISSIONS SUMMARY: REFINERY PROCESS HEATER, 2/83 - 6/83

TEST #	FUEL& NG-FG/AG/ NO.6@	PROC. RATE M3/H	HEAT INPUT MW	O2 %	NO PPM*	NO NG/J	CO PPM*	CO2 %	STACK K	T F	HTR EFF	SEC. AIR REG. %OPEN	FURN. PRESS. -IWC.	STAGE HT. M	FT	LANC DIA IN	BRN EQUI RATIO	COMMENTS
2/8-1	0/21/79	75.9	11.2	3.6	272	150	5	13	638	689	77.3	33	.37	-	-	-	1.19	LONG TERM BASELINE
2/8-1A	0/21/79	75.9	10.9	3.9	286	158	2	12.7	639	690	-	33	.37	-	-	-	-	LONG TERM BASELINE
2/8-1B	0/21/79	75.9	10.9	3.6	281	155	4	13	639	690	-	33	.37	-	-	-	-	LONG TERM BASELINE
2/8-1C	0/21/79	75.9	10.9	3.4	267	147	5	13	638	689	-	33	.37	-	-	-	-	LONG TERM BASELINE
2/8-1D	0/21/79	75.9	10.9	3.5	266	147	6	13.2	637	688	-	33	.37	-	-	-	-	LONG TERM BASELINE
2/8-1E	0/21/79	75.9	10.9	3.5	262	144	10	13.1	638	689	-	33	.37	-	-	-	-	LONG TERM BASELINE
2/8-1F	0/21/79	75.9	10.9	3.1	245	135	6	13.2	638	689	-	33	.37	-	-	-	-	LONG TERM BASELINE
2/9-1	0/21/79	75.9	10.9	4.1	290	160	6	12	643	698	75.8	33	.33	-	-	-	1.22	BASELINE
2/9-1A	0/21/79	75.9	10.9	4.2	280	155	7	12.1	643	698	-	33	.33	-	-	-	-	BASELINE
2/9-1B	0/21/79	75.9	10.9	3.9	267	147	4	12.7	642	696	-	33	.33	-	-	-	-	BASELINE
2/9-1C	0/21/79	75.9	10.9	3.8	286	158	3	12.8	641	695	-	33	.33	-	-	-	-	BASELINE
2/9-1D	0/21/79	75.9	10.9	3.6	282	155	2	15.3	641	695	-	33	.33	-	-	-	-	BASELINE
2/9-2	0/21/79	75.9	10.9	4.1	276	152	4	12.5	643	698	76.6	33	.34	-	-	-	1.22	BASELINE
2/10-1	0/25/75	52.6	9.4	4.2	335	184	4	13.1	634	681	77.2	33	.28	-	-	-	1.22	BASELINE
2/10-2	0/25/75	52.6	9.4	1.8	235	129	8	14.7	615	648	79.3	25	.34	.12	.4	-	1.09	LEA
2/10-3	0/25/75	52.6	9.4	3.8	204	112	8	13.2	627	670	77.6	25	.15	.12	.4	-	.69	SCA (ND), 4" PORTS
2/10-4	0/25/75	52.6	9.4	2.2	106	158	41	14	610	639	79	25	.15	.12	.4	-	.61	SCA + LEA (ND), 4" PORTS
2/10-5	0/25/75	52.6	9.4	4.1	328	180	5	13.4	635	684	77.4	33	.23	-	-	-	1.22	BASELINE
2/11-1	0/18/82	91.8	13.1	4.5	325	179	7	12.8	655	719	76.5	50	.38	-	-	-	1.27	BASELINE
2/11-1A	0/18/82	91.8	13.1	3.8	284	156	4	12.7	655	719	-	50	.38	-	-	-	-	BASELINE
2/11-1D	0/18/82	91.8	13.1	4.2	304	168	5	12.4	655	719	-	50	.38	-	-	-	-	BASELINE
2/11-2	0/18/82	91.8	13.1	1.8	213	118	33	14.9	624	663	79.7	25	.36	-	-	-	1.09	LEA
2/11-3	0/18/82	91.8	13.1	4	225	124	10	12.6	638	689	77.1	25	.2	.12	.4	-	.81	SCA (ND), 4" PORTS
2/11-4	0/21/79	91.8	11.5	2	137	75	41	15.6	636	686	79.4	25	.13	.12	.4	-	.71	SCA + LEA (ND), 4" PORTS
2/11-5	0/21/79	91.8	11.5	4	324	178	14	12.3	643	698	76.3	50	.27	-	-	-	1.23	BASELINE
2/14-1	0/22/78	75.9	10.7	3.7	271	149	15	12.7	649	708	76.4	33	.38	-	-	-	1.2	BASELINE
2/14-2	0/22/78	75.9	10.7	3.8	219	120	16	13.3	632	678	79.4	25	.36	1.2	4	1.2	.87	SCA (FD) 4' STG HGT, MED. BER, LANCES TOWARD BURNER
2/14-3	0/22/78	75.9	10.7	3.8	198	109	18	13.7	615	647	80.5	10	.31	1.2	4	1.2	.71	SCA (FD) 4' STG HGT, MIN. BER, LANCES TOWARD BURNER
2/14-4	0/22/78	75.9	10.7	4.1	200	110	29	13.3	634	682	79.3	25	.23	1.2	4	1.2	.73	SCA (FD) 4' STG HGT, MIN. BER, LANCES TOWARD HEATER
2/14-5	0/22/78	75.9	10.7	3.9	260	143	10	13.6	646	704	77.4	33	.4	-	-	-	1.22	BASELINE, REPEAT
2/15-1	0/22/79	75.9	11.5	3.8	304	167	14	13.2	646	703	76.5	33	.41	-	-	-	1.2	BASELINE
2/15-2	0/20/80	75.9	11.5	3.8	285	157	8	13.2	645	702	78.3	25	.4	0.9	3	1.2	.98	SCA (FD) 3' STG HGT, MAX. BER
2/15-3	0/20/80	75.9	11.5	3.8	276	152	10	13.3	641	694	79.1	20	.39	0.9	3	1.2	.89	SCA (FD) 3' STG HGT, MED. BER
2/15-4	0/19/81	75.9	12.7	3.8	237	131	11	13.1	630	674	79.6	10	.36	0.9	3	1.2	.78	SCA (FD) 3' STG HGT, MIN. BER
2/15-5	0/19/81	75.9	12.7	3.9	271	149	13	13.5	639	690	79.3	20	.28	0.6	2	1.2	.79	SCA (FD) 2' STG HGT, MIN. BER
2/15-6	0/21/79	75.9	11.3	3.8	302	166	7	13.2	639	691	79.1	20	.27	0.6	2	1.2	.88	SCA (FD) 2' STG HGT, MED. BER
2/15-7	0/21/79	75.9	11.3	4	308	170	9	12.2	645	702	77.9	25	.27	0.6	2	1.2	1.01	SCA (FD) 2' STG HGT, MAX. BER
2/15-8	0/21/79	75.9	11.3	3.9	297	164	22	13	643	698	77.1	33	.36	-	-	-	1.22	BASELINE, REPEAT
2/16-1	0/18/82	75.9	13.6	4.1	301	166	3	12.2	648	707	76.2	33	.42	-	-	-	1.23	BASELINE
2/16-2	0/17/83	76.3	14.6	4.1	257	142	11	12.8	640	693	78.9	33	.32	2.4	8	1.2	1.06	SCA (FD) 8' STG HGT, MAX. BER
2/16-3	0/16/84	76.3	14.9	4.2	240	133	13	13.1	631	676	79.6	20	.38	2.4	8	1.2	1	SCA (FD) 8' STG HGT, MED. BER
2/16-4	0/17/83	76.4	14.3	5.4	269	149	12	11.9	616	650	79.1	33	.29	2.4	8	1.2	.98	SCA (FD) 8' STG HGT, MIN. BER
2/16-5	0/16/84	76.3	15.3	3.9	308	170	4	12.8	653	716	76.7	33	.39	-	-	-	1.22	BASELINE, REPEAT
2/17-1	0/19/81	76.1	13.6	5.7	344	190	5	11.6	669	745	74.3	50	.29	-	-	-	1.36	BASELINE
2/17-2	0/19/81	76.1	13.6	5.7	324	179	4	11.7	662	733	76.7	40	.29	1.2	4	1.2	1.18	SCA (FD) 4' STG HGT, MAX. BER
2/17-3	0/19/81	76.1	13.6	5.8	315	174	4	11.8	651	712	77.3	33	.33	1.2	4	1.2	1.11	SCA (FD) 4' STG HGT, MED. BER
2/17-4	0/19/81	76.1	13.6	5.8	282	155	8	11.7	643	698	77.6	25	.3	1.2	4	1.2	.97	SCA (FD) 4' STG HGT, MIN. BER
2/17-5	0/19/81	76.1	13.6	5.9	347	191	6	11.3	669	744	73.9	50	.37	-	-	-	1.37	BASELINE, REPEAT
2/22-1	0/17/83	75.9	15.2	6.1	345	191	3	11.8	671	748	75.3	50	.35	-	-	-	1.39	BASELINE
2/22-2	0/17/83	75.9	14.4	6	331	183	5	11.7	667	741	77.1	40	.29	1.2	4	1.2	1.22	SCA (FD) 4' STG HGT, MAX. BER
2/22-3	0/17/83	75.9	14.5	4.9	306	169	6	12.4	657	723	78.3	33	.37	1.2	4	1.2	1.13	SCA (FD) 4' STG HGT, MAX. BER
2/22-4	0/17/83	75.9	13.8	3.9	277	153	5	13	645	701	79.5	25	.36	1.2	4	1.2	1.05	SCA (FD) 4' STG HGT, MAX. BER
2/22-5	0/18/82	75.9	13.8	2.9	219	121	9	13.7	636	685	80.5	10	.39	1.2	4	1.2	.97	SCA (FD) 4' STG HGT, MAX. BER
2/22-6	18/0/82	75.9	13.7	2.1	173	95	28	14.5	-	-	-	10	-	1.2	4	1.2	.93	SCA (FD) 4' STG HGT, MAX. BER
2/22-7	18/0/82	75.9	13.6	5.8	361	199	6	11.8	656	722	75.9	50	.33	-	-	-	1.37	BASELINE, REPEAT

EMISSIONS SUMMARY: REFINERY PROCESS HEATER, 2/83 - 6/83 (CONTINUED)

TEST #	FUEL@ NG-FG/AG/ NO.6@	PROC. RATE M3/H	HEAT INPUT MW	O2 %	NO PPM*	NO NG/J	CO PPM*	CO2 %	STACK T K	STACK T F	HTR EFF	SEC. AIR REG. %OPEN	FURN. PRESS. -IWC.	STAGE HT. M	STAGE HT. FT	LANC DIA IN	BRN EQUI RATIO	COMMENTS
2/23-1	19/0 81	75.9	13.6	5.7	345	190	6	11.4	665	737	74.8	50	.35	-	-	-	1.36	BASELINE
2/23-2	19/0/81	75.9	13.6	6	318	175	6	11.6	653	716	77.4	40	.31	1.2	4	1.2	1.39	SCA (FD) 4' STG HGT, MED. BER
2/23-3	19/0/81	75.9	13.6	4.8	288	159	7	12.3	644	700	78.6	50	.35	1.2	4	1.2	.98	SCA (FD) 4' STG HGT, MED. BER
2/23-4	19/0/81	75.9	13.6	4.1	267	147	13	13.2	635	683	79.8	40	.38	1.2	4	1.2	.97	SCA (FD) 4' STG HGT, MED. BER
2/23-4R	25/0/75	75.9	10.7	4.1	330	181	4	13	631	676	79.7	33	.2	1.2	4	1.2	.9	REPEAT 2/23-4, OIL FLOW DECREASED
2/23-5	25/0/75	75.9	10.7	3	271	149	17	14.1	618	653	81.1	25	.2	1.2	4	1.2	.83	SCA (FD) 4' STG HGT, MED. BER
2/23-6	25/0/75	75.9	10.7	4.2	263	145	5	13	-	-	-	35	.2	1.2	4	1.2	.91	SCA (FD) 4' STG HGT, MED. BER
2/23-7	25/0/75	75.9	10.7	5.4	302	166	2	12.2	-	-	-	40	.2	1.2	4	1.2	1	SCA (FD) 4' STG HGT, MED. BER
2/23-8	25/0/75	75.9	10.7	5.7	349	192	2	11.6	656	722	75.4	50	.33	-	-	-	1.36	BASELINE, REPEAT
2/24-1	20/0/80	76.3	9.4	5.8	378	208	3	12.6	646	703	77	50	.22	-	-	-	1.37	BASELINE
2/24-2	20/0/80	76.3	9.4	6.1	281	155	8	11.6	626	667	78.4	33	.13	1.2	4	1.2	.82	SCA (FD) 4' STG HGT, MIN. BER
2/24-3	20/0/80	76.5	9.4	5.1	231	127	11	13	618	653	80.3	15	.13	1.2	4	1.2	.74	SCA (FD) 4' STG HGT, MIN. BER
2/24-4	20/0/80	76.5	9.4	4.9	225	124	12	12.9	618	653	80.3	15	.13	1.2	4	1.2	.73	SCA (FD) 4' STG HGT, MIN. BER
2/24-5	22/0/78	76.5	8.3	5.9	380	209	6	12.1	642	696	76.5	50	.23	-	-	-	1.38	BASELINE, REPEAT
2/25-1	20/0/80	50.3	7.4	5.8	404	222	6	12.2	629	673	77.2	33	.23	-	-	-	1.37	BASELINE
2/25-2	20/0/80	50.3	7.4	5.7	338	186	5	12.7	624	663	79.7	10	.21	0.9	3	1.2	1.03	SCA, 3' STG HGT, MAX. BER
2/25-3	20/0/80	50.3	7.4	5.8	328	181	9	12.2	617	651	79.5	10	.19	0.9	3	1.2	.88	SCA, 3' STG HGT, MED. BER
2/25-4	20/0/80	50.3	7.4	6.1	281	155	16	11.9	597	615	80.2	10	.1	0.9	3	1.2	.66	SCA, 3' STG HGT, MIN. BER
2/25-5	22/0/78	50.3	5.1	5.9	379	208	6	11.9	629	672	76.4	33	.27	-	-	-	1.38	BASELINE, REPEAT
2/28-1	16/0/84	92.8	12.5	4.3	312	172	7	13.1	652	714	77.4	33	.23	-	-	-	1.25	BASELINE
2/28-2	16/0/84	92.8	12.5	4.3	288	159	7	12.3	637	688	79	25	.21	1.2	4	1.2	1.03	SCA (FD) 4' STG HGT, MAX. BER
2/28-3	18/0/82	92.8	10.8	4.2	257	142	11	12.6	630	674	79.5	25	.19	1.2	4	1.2	.87	SCA (FD) 4' STG HGT, MED. BER
2/28-4	18/0/82	92.8	10.8	4.1	222	123	17	12.9	612	643	80.6	25	.1	1.2	4	1.2	.74	SCA (FD) 4' STG HGT, MIN. BER
2/28-5	18/0/82	92.8	10.8	4.6	308	170	7	12.6	-	-	-	33	.27	-	-	-	1.27	BASELINE, REPEAT
3/2-1	19/0/81	75.9	10.7	5.9	359	198	8	12.6	657	692	77.3	33	.3	-	-	-	1.38	BASELINE
3/3-1	26/0/74	75.9	11.9	5.8	351	192	5	12.3	647	706	76.2	33	.21	-	-	-	1.37	BASELINE
3/3-1	26/0/74	75.9	11.9	6	353	193	4	13	665	737	76.1	33	.23	-	-	-	1.39	BASELINE
3/4	17/0/83	77.1	11.4	6.1	374	207	8	10.7	657	723	73.8	33	.32	-	-	-	1.39	BASELINE
6/8	29/0/71	77.1	15.6	3.3	235	131	5	14.3	686	776	78	100	.27	-	-	-	1.19	BASELINE
6/9-1	31/0/69	77.1	13.5	3.4	246	135	8	11.5	686	776	74.6	100	.32	-	-	-	1.19	BASELINE
6/9-2	35/0/65	77.1	13.4	2.2	165	91	15	12.5	641	694	79.4	50	.16	1.2	4	1.2	.9	LOW NOX, PARTICULATE, N20
6/9-3	37/0/63	77.1	13.9	2.1	145	80	4	12.7	639	690	79.7	50	.13	1.2	4	1.2	.9	LOW NOX, PARTICULATE
6/10-1	32/0/68	75.9	14.2	3.3	252	139	5	11.4	684	772	75.4	100	.28	-	-	-	1.19	BASELINE
6/10-2	37/0/63	75.9	14.2	2.5	188	103	9	12.3	642	696	78.3	50	.16	1.2	4	1.2	.94	LOW NOX, SO2, SO3, ANDERSON

@FUEL GIVEN AS PERCENTAGE OF NATURAL GAS-FUEL GAS (NG-FG), ABSORBER GAS (AG), AND NO. 6 OIL BY INPUT

*ppmv, dry, corrected to 3% O_2

NO on a mass basis is in terms of NO_2

APPENDIX C

TABULATION OF 15-MINUTE AVERAGES

PETROLEUM PROCESS HEATER UNDER BASELINE AND STAGED COMBUSTION AIR OPERATION

APPENDIX C

This appendix includes the computer printout sheets for the 15-minute averages for the extended duration test of a petroleum process heater under baseline conditions and then modified to incorporate staged combustion air. These data were recorded on Apple computer data discs and then transcribed onto sheets with data reduction by the KVB data analysis program. Presented in this appendix are the baseline and 15-minute averages for each day.

An average fuel firing factor, F_d, was calculated for both the three nonscrubbed refinery gas samples and the two absorber gas samples. The F_d factor average of the three nonscrubbed refinery gas samples is:

$$8601 \frac{\text{dscf}}{10^6 \text{ Btu}} \left(2.31 \times 10^{-7} \frac{\text{dscm}}{\text{J}}\right)$$

with a standard deviation of

$$27 \frac{\text{dscf}}{10^6 \text{ Btu}} \left(1 \times 10^{-9} \frac{\text{dscm}}{\text{J}}\right) .$$

The coefficient of variation for F_d is 0.3 percent indicating a very small deviation from the average value. This F_d factor was used for converting the CO and NO data to a mass emissions basis (nanograms per joule) for the time period of March 14 - 1215 hours to March 25 - 1800 hours.

The F_d factor average of the two absorber gas samples is

$$8523 \frac{\text{dscf}}{10^6 \text{ Btu}} \left(2.29 \times 10^{-7} \frac{\text{dscm}}{\text{J}}\right)$$

with a standard deviation of

$$20 \frac{\text{dscf}}{10^6 \text{ Btu}} \left(1 \times 10^{-9} \frac{\text{dscm}}{\text{J}}\right) .$$

The coefficient of variation for F_d is 0.2 percent indicating a very small deviation from the average value. The F_d factor was used for converting CO and NO data to a mass emissions basis (nanograms per joule) for the time period of March 25 - 1800 hours to April 1 - 0845 hours.

KVB TESTING CODES A THROUGH K

Code	Explanation
A	Testing Begins
B	Testing Ends
C	Instrument Calibrations
D	NO Instrument Out of Service (maintenance)
E	O_2 Instrument Out of Service (maintenance)
F	CO_2 Instrument Out of Service (maintenance)
G	CO Instrument Out of Service (maintenance)
H	Boiler (or unit) Out of Service
I	Continuous Monitor
J	Continuous Monitor Out of Service (maintenance)
K	Power Failure
L	Fuel Gas Drum/Natural Gas/Propane
M	Absorber Gas

SITE 2 BASELINE

DATE 3-14-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	0	0	0	0	0	0	
1230	3.8	10	5	70	2	36	A/C/L
1245	3.8	10.6	4	70	1	36	
1300	3.7	10.7	6	80	2	41	
1315	3.9	10.6	6	71	2	36	
1330	3.2	11.5	5	100	2	51	
1345	2.6	12.1	6	116	2	59	
1400	2.9	12.1	7	139	2	71	
1415	3.6	11.5	9	149	3	76	
1430	4	11.2	8	155	3	79	
1445	4.3	11	7	156	2	80	
1500	4.4	11	7	160	2	82	
1515	4.4	11	7	158	2	81	
1530	4.3	11.2	7	153	2	78	
1545	4.2	11.2	5	152	2	78	
1600	4.1	11.4	1	152	0	78	
1615	4.3	11.3	3	155	1	79	
1630	4.2	11.3	5	156	2	80	
1645	4.1	11.3	5	153	2	78	
1700	0	0	0	0	0	0	J
1715	0	0	0	0	0	0	J
1730	0	0	0	0	0	0	J
1745	0	0	0	0	0	0	J
1800	0	0	0	0	0	0	J
1815	0	0	0	0	0	0	J
1830	4.2	10.7	12	144	4	73	
1845	4.3	11.3	13	147	4	75	
1900	4.4	11.3	16	147	5	75	
1915	4.6	11.3	16	152	5	78	
1930	4.6	11.4	13	152	4	78	
1945	4.6	11.6	17	148	6	76	
2000	4.3	11.8	25	154	8	79	
2015	4.5	11.6	14	158	5	81	
2030	4.6	11.8	11	154	4	79	
2045	4.7	11.7	10	157	3	80	
2100	4.7	11.9	10	157	3	80	
2115	4.8	12	7	158	2	81	
2130	4.8	12.2	6	156	2	80	
2145	4.8	12.2	6	156	2	80	
2200	5.1	11.9	5	159	2	81	
2215	5.1	11.9	5	159	2	81	
2230	5.1	11.9	5	159	2	81	
2245	5.1	11.9	5	159	2	81	
2300	5.1	11.9	5	159	2	81	
2315	5	11.3	7	155	2	79	
2330	0	0	0	0	0	0	J
2345	0	0	0	0	0	0	J
2400	0	0	0	0	0	0	J

NO on a mass basis is in terms of NO_2

SITE 2 BASELINE

DATE 3-15-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	5.3	11.1	5	158	2	81	
30	5.3	11.3	6	158	2	81	
45	5.2	11.5	0	159	0	81	
100	5.2	11.4	5	161	2	82	
115	5.1	11.5	7	160	2	82	
130	4.9	11.7	8	156	3	80	
145	5.2	11.5	3	159	1	81	
200	5.1	11.4	4	157	1	80	
215	5.3	11.1	3	160	1	82	
230	5.3	11.3	8	157	3	80	
245	5.2	11.4	0	153	0	78	
300	5.2	11.3	0	154	0	79	
315	5.3	11.2	2	155	1	79	
330	5.1	11.4	3	153	1	78	
345	5.3	11	3	153	1	78	
400	5.3	10.9	4	154	1	79	
415	5.3	11.2	7	153	3	78	
430	5.4	11.1	6	155	2	79	
445	5.3	11.2	6	153	2	78	
500	5.5	11.3	7	156	3	80	
515	5.5	11.5	5	155	2	79	
530	5.5	11.5	4	155	1	79	
545	5.4	11.6	3	156	1	80	
600	5.6	11.4	4	158	1	81	
615	5.5	11.4	2	156	1	80	
630	5.5	11.6	2	154	1	79	
645	5.5	11.6	1	154	0	79	
700	5.5	11.7	0	153	0	78	
715	5.5	11.7	2	152	1	78	
730	5.3	11.2	6	150	2	77	
745	0	0	0	0	0	0	J/C
800	0	0	0	0	0	0	J
815	5.4	10.9	11	150	4	77	
830	0	0	0	0	0	0	J
845	0	0	0	0	0	0	J
900	0	0	0	0	0	0	J
915	0	0	0	0	0	0	J
930	0	0	0	0	0	0	J
945	0	0	0	0	0	0	J
1000	0	0	0	0	0	0	J
1015	0	0	0	0	0	0	J
1030	0	0	0	0	0	0	J
1045	0	0	0	0	0	0	J
1100	0	0	0	0	0	0	J
1115	0	0	0	0	0	0	J
1130	0	0	0	0	0	0	J
1145	4.9	11.7	20	147	7	75	
1200	4.9	11.7	20	147	7	75	

NO on a mass basis is in terms of NO_2

SITE 2 BASELINE

DATE 3-15-1983
LOAD 11500 BBL/D

15 MIN DATA
DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	4.9	11.7	20	147	7	75	
1230	4.9	11.7	20	147	7	75	
1245	4.9	11.7	20	147	7	75	
1300	4.9	11.7	20	147	7	75	
1315	0	0	0	0	0	0	J
1330	0	0	0	0	0	0	J
1345	4.3	0	0	142	0	72	
1400	0	0	0	0	0	0	J
1415	4.4	11.5	18	148	6	76	
1430	4	11.6	22	131	7	67	
1445	3.1	12.3	24	127	8	65	
1500	0	0	0	0	0	0	J
1515	0	0	0	0	0	0	J
1530	0	0	0	0	0	0	J
1545	0	0	0	0	0	0	J
1600	2.4	11.9	24	61	7	31	
1615	2.3	11.8	22	58	7	30	
1630	0	0	0	0	0	0	J
1645	4.3	10.7	22	75	7	38	
1700	4.1	11.3	16	88	5	45	C
1715	4.1	11.3	16	88	5	45	
1730	4.4	11.9	13	100	4	51	
1745	4.5	11.4	14	81	5	41	
1800	4.1	11.6	13	83	4	42	
1815	4.1	11.6	13	83	4	42	
1830	4.4	11.3	13	94	4	48	
1845	4.3	11.6	13	91	4	46	
1900	4.4	11.3	13	91	4	46	
1915	4.2	12.1	14	124	5	63	
1930	4.2	12.1	14	124	5	63	
1945	4.7	11.2	14	89	5	45	
2000	4.7	11	13	73	4	37	
2015	4.4	11.6	14	85	5	43	
2030	4.6	11.3	13	83	4	42	
2045	4.6	11.3	13	83	4	42	
2100	4.7	11.5	14	94	5	48	
2115	0	0	0	0	0	0	J
2130	0	0	0	0	0	0	J
2145	0	0	0	0	0	0	J
2200	0	0	0	0	0	0	J
2215	0	0	0	0	0	0	J
2230	0	0	0	0	0	0	J
2245	0	0	0	0	0	0	J
2300	0	0	0	0	0	0	J
2315	0	0	0	0	0	0	J
2330	0	0	0	0	0	0	J
2345	0	0	0	0	0	0	J
2400	0	0	0	0	0	0	J

NO on a mass basis is in terms of NO_2

SITE 2 BASELINE

DATE 3-16-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	4.6	9.8	5	74	2	38	
30	4.6	10.1	0	73	0	37	
45	4.2	10.8	0	73	0	37	
100	4.4	10.8	0	76	0	39	
115	4.5	10.7	0	69	0	35	
130	3.7	12.1	0	114	0	58	
145	4.3	11.7	0	131	0	67	
200	4.8	11.2	0	120	0	61	
215	4.9	10.9	0	105	0	54	
230	5	10.7	0	101	0	52	
245	4.8	10.8	0	102	0	52	
300	5.1	10.5	0	92	0	47	
315	4.8	10.5	0	77	0	39	
330	4.5	11.2	0	105	0	54	
345	4.7	10.9	146	107	50	55	
400	4.2	11.4	0	115	0	59	
415	4.7	11	0	123	0	63	
430	4.7	10.8	115	100	40	51	
445	4.6	11.2	24	121	8	62	
500	5.1	10.4	23	97	8	49	
515	4.5	10.9	24	97	8	49	
530	4.4	11.3	22	120	7	61	
545	4.7	11	13	122	4	62	
600	4.3	11.5	13	133	4	68	
615	4.8	10.9	8	125	3	64	
630	4.6	11.1	156	115	54	59	
645	4.5	11.3	0	124	0	63	
700	4.7	11.4	5	130	2	66	
715	4.7	11.5	0	124	0	63	
730	4.5	11.1	90	131	31	67	
745	4.9	11.1	191	120	67	61	C
800	0	0	0	0	0	0	J
815	0	0	0	0	0	0	J
830	0	0	0	0	0	0	J
845	0	0	0	0	0	0	J
900	0	0	0	0	0	0	J
915	4.8	9.9	14	72	5	37	
930	4.6	10.3	13	86	4	44	
945	4.8	10.7	14	142	5	72	
1000	4.7	11	14	156	5	80	
1015	0	0	0	0	0	0	J
1030	0	0	0	0	0	0	J
1045	4.5	11	12	155	4	79	
1100	4.5	11.2	11	156	4	80	
1115	4.4	11.2	11	157	4	80	
1130	4.4	11.4	9	159	3	81	
1145	4.2	11.7	11	161	4	82	
1200	4.2	11.6	10	150	3	77	

NO on a mass basis is in terms of NO_2

SITE 2 BASELINE

DATE 3-16-1983
LOAD 11500 BBL/D

15 MIN DATA
DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	4.3	11	10	89	3	45	
1230	3.9	11.1	10	78	3	40	
1245	3.7	11.3	13	75	4	38	
1300	3.4	11.5	10	75	3	38	
1315	3.4	11.6	10	73	3	37	B
1330	0	0	0	0	0	0	
1345	0	0	0	0	0	0	
1400	0	0	0	0	0	0	
1415	0	0	0	0	0	0	
1430	0	0	0	0	0	0	
1445	0	0	0	0	0	0	
1500	0	0	0	0	0	0	
1515	0	0	0	0	0	0	
1530	0	0	0	0	0	0	
1545	0	0	0	0	0	0	
1600	0	0	0	0	0	0	
1615	0	0	0	0	0	0	
1630	0	0	0	0	0	0	
1645	0	0	0	0	0	0	
1700	0	0	0	0	0	0	
1715	0	0	0	0	0	0	
1730	0	0	0	0	0	0	
1745	0	0	0	0	0	0	
1800	0	0	0	0	0	0	
1815	0	0	0	0	0	0	
1830	0	0	0	0	0	0	
1845	0	0	0	0	0	0	
1900	0	0	0	0	0	0	
1915	0	0	0	0	0	0	
1930	0	0	0	0	0	0	
1945	0	0	0	0	0	0	
2000	0	0	0	0	0	0	
2015	0	0	0	0	0	0	
2030	0	0	0	0	0	0	
2045	0	0	0	0	0	0	
2100	0	0	0	0	0	0	
2115	0	0	0	0	0	0	
2130	0	0	0	0	0	0	
2145	0	0	0	0	0	0	
2200	0	0	0	0	0	0	
2215	0	0	0	0	0	0	
2230	0	0	0	0	0	0	
2245	0	0	0	0	0	0	
2300	0	0	0	0	0	0	
2315	0	0	0	0	0	0	
2330	0	0	0	0	0	0	
2345	0	0	0	0	0	0	
2400	0	0	0	0	0	0	

NO on a mass basis is in terms of NO_2

SITE 2 BASELINE

DATE 3-31-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	0	0	0	0	0	0	
30	0	0	0	0	0	0	
45	0	0	0	0	0	0	
100	0	0	0	0	0	0	
115	0	0	0	0	0	0	
130	0	0	0	0	0	0	
145	0	0	0	0	0	0	
200	0	0	0	0	0	0	
215	0	0	0	0	0	0	
230	0	0	0	0	0	0	
245	0	0	0	0	0	0	
300	0	0	0	0	0	0	
315	0	0	0	0	0	0	
330	0	0	0	0	0	0	
345	0	0	0	0	0	0	
400	0	0	0	0	0	0	
415	0	0	0	0	0	0	
430	0	0	0	0	0	0	
445	0	0	0	0	0	0	
500	0	0	0	0	0	0	
515	0	0	0	0	0	0	
530	0	0	0	0	0	0	
545	0	0	0	0	0	0	
600	0	0	0	0	0	0	
615	0	0	0	0	0	0	
630	0	0	0	0	0	0	
645	0	0	0	0	0	0	
700	0	0	0	0	0	0	
715	0	0	0	0	0	0	
730	0	0	0	0	0	0	
745	0	0	0	0	0	0	
800	0	0	0	0	0	0	
815	0	0	0	0	0	0	
830	0	0	0	0	0	0	C
845	4	0	5	102	2	52	A/F/M
900	3.6	10.6	5	108	2	55	
915	3.6	10.7	4	108	1	55	
930	3.5	10.7	4	107	1	55	
945	3.4	10.9	4	105	1	54	
1000	3.4	10.8	5	107	2	55	
1015	3.5	10.6	4	107	1	55	
1030	3.3	10.7	4	106	1	54	
1045	3.4	10.8	4	107	1	55	
1100	4.1	10.7	4	115	1	59	
1115	4.3	10.7	4	121	1	62	
1130	4.4	10.6	4	122	1	62	
1145	4.4	10.6	4	122	1	62	
1200	4.1	10.5	4	122	1	62	

NO on a mass basis is in terms of NO_2

SITE 2 BASELINE

DATE 3-31-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	4.4	10.4	4	125	1	64	
1230	4.4	10.4	4	126	1	64	
1245	4.4	10.3	4	128	1	60	C
1300	3.3	10.6	4	115	1	59	
1315	2.2	10.9	4	104	1	53	
1330	2.1	10.9	4	103	1	53	
1345	2	11.4	7	102	2	52	
1400	2.2	11.9	9	104	3	53	
1415	2	11.9	10	104	3	53	
1430	1.6	12.6	10	100	3	51	
1445	1.9	12.5	10	104	3	53	
1500	1.9	12.6	10	103	3	53	
1515	1.8	12.7	10	102	3	52	
1530	1.8	12.7	10	103	3	53	
1545	1.9	12.7	10	103	3	53	
1600	2.6	12.4	10	111	3	57	
1615	2.9	12.2	10	113	3	58	
1630	2.9	12.2	11	114	3	58	
1645	3.7	11.7	11	121	4	62	
1700	3.5	11.8	11	118	4	60	
1715	4.5	11.5	8	126	3	64	
1730	4.1	11.5	9	122	3	62	
1745	4.3	11.5	8	123	3	63	
1800	3.8	11.7	8	119	3	61	
1815	3.9	11.7	9	120	3	61	
1830	4	11.6	9	120	3	61	
1845	4	11.5	8	121	3	62	
1900	4.1	11.5	8	122	3	62	
1915	4.1	11.6	8	122	3	62	
1930	4.2	11.5	9	122	3	62	
1945	4.3	11.4	8	122	3	62	
2000	4.4	11.3	8	122	3	62	
2015	4.2	11.3	8	122	3	62	
2030	4.1	11.3	8	120	3	61	
2045	4.2	11.3	8	121	3	62	
2100	4.2	11.6	8	120	3	61	
2115	4.3	11.5	9	120	3	61	
2130	4.4	11.5	9	120	3	61	
2145	4.4	11.5	8	120	3	61	
2200	4.4	11.5	8	120	3	61	
2215	4.4	11.3	9	120	3	61	
2230	4.4	11.5	8	121	3	62	
2245	4.4	11.6	8	121	3	62	
2300	4.5	11.6	8	121	3	62	
2315	4.5	11.6	8	120	3	61	
2330	4.4	11.5	8	120	3	61	
2345	4.3	11.4	8	118	3	60	
2400	4.3	11.4	8	118	3	60	

NO on a mass basis is in terms of NO_2

SITE 2 BASELINE

DATE 4-1-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	4.3	11.4	8	118	3	60	
30	4.2	11.6	8	118	3	60	
45	4.3	11.6	9	119	3	61	
100	5.1	11.2	8	125	3	64	
115	5.3	11.1	8	126	3	64	
130	5.4	11.1	8	124	3	63	
145	4.5	11.5	9	118	3	60	
200	4.3	11.6	9	118	3	60	
215	4.5	11.5	9	119	3	61	
230	4.5	11.6	9	118	3	60	
245	4.7	11.5	9	119	3	61	
300	4.6	11.6	9	118	3	60	
315	4.5	11.6	9	118	3	60	
330	4.6	11.5	9	117	3	60	
345	4.5	11.5	9	116	3	59	
400	4.6	11.3	9	116	3	59	
415	4.6	11.5	9	117	3	60	
430	.7	12.6	1627	57	449	29	
445	2.9	12.4	29	102	9	52	
500	2.8	12.3	14	102	4	52	
515	2.9	12.3	13	103	4	53	
530	2.9	12.1	12	102	4	52	
545	2.9	12.1	12	102	4	52	
600	2.9	12.2	12	102	4	52	
615	2.8	12.4	12	101	4	52	
630	3	12.4	12	103	4	53	
645	2.9	12.3	12	102	4	52	
700	2.9	12.2	12	102	4	52	
715	2.9	10.9	15	104	5	53	C
730	2.8	10.8	15	105	5	54	
745	2.8	10.7	11	105	3	54	
800	2.9	10.5	11	107	3	55	
815	2.8	10.6	11	107	3	55	
830	2.8	10.5	11	108	3	55	
845	2.7	10.6	109	108	33	55	B
900	0	0	0	0	0	0	
915	0	0	0	0	0	0	
930	0	0	0	0	0	0	
945	0	0	0	0	0	0	
1000	0	0	0	0	0	0	
1015	0	0	0	0	0	0	
1030	0	0	0	0	0	0	
1045	0	0	0	0	0	0	
1100	0	0	0	0	0	0	
1115	0	0	0	0	0	0	
1130	0	0	0	0	0	0	
1145	0	0	0	0	0	0	
1200	0	0	0	0	0	0	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-16-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	0	0	0	0	0	0	
1230	0	0	0	0	0	0	
1245	0	0	0	0	0	0	
1300	0	0	0	0	0	0	B
1315	0	0	0	0	0	0	
1330	0	0	0	0	0	0	
1345	0	0	0	0	0	0	
1400	0	0	0	0	0	0	
1415	0	0	0	0	0	0	
1430	0	0	0	0	0	0	
1445	0	0	0	0	0	0	
1500	0	0	0	0	0	0	
1515	0	0	0	0	0	0	
1530	0	0	0	0	0	0	
1545	0	0	0	0	0	0	
1600	0	0	0	0	0	0	
1615	3.4	10.4	11	55	4	28	A/L
1630	2.6	10.9	19	51	6	26	
1645	2.6	11.1	23	51	7	26	
1700	2.2	11.1	20	45	6	23	
1715	2.2	11.1	28	44	8	22	
1730	4	10	24	66	8	34	
1745	4	10.1	26	64	9	33	
1800	4.1	10.3	29	63	10	32	
1815	4.3	10.7	26	63	9	32	
1830	4.2	10.8	26	63	9	32	
1845	4.3	10.6	24	61	8	31	
1900	4.4	10.6	26	62	9	32	
1915	4.5	10.5	19	62	6	32	
1930	4.5	10.7	21	60	7	31	
1945	4.4	10.7	24	58	8	30	
2000	4.4	10.5	25	59	8	30	
2015	4.5	10.3	19	59	6	30	
2030	4.6	10.1	21	59	7	30	
2045	4.5	10.2	19	59	6	30	
2100	4.6	10.2	18	59	6	30	
2115	4.7	10.1	20	59	7	30	
2130	4.3	10.9	24	81	8	41	
2145	4	11.7	23	101	8	52	
2200	5.2	10.4	24	96	9	49	
2215	5.5	10	23	75	8	38	
2230	5.1	10.1	22	64	8	33	
2245	4.5	10	11	61	4	31	
2300	4.5	10	10	60	3	31	
2315	4.6	10.2	4	61	1	31	
2330	4.9	10.2	5	62	2	32	
2345	4.9	10	2	62	1	32	
2400	4.9	10.1	0	66	0	34	G

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-17-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	5.1	9.9	0	62	0	32	G
30	5.1	9.9	0	63	0	32	G
45	5	9.9	0	63	0	32	G
100	5	9.8	8	63	3	32	G
115	4.8	10	0	61	0	31	G
130	5	9.8	0	62	0	32	G
145	4.7	10.2	0	66	0	34	G
200	4.4	10.6	0	81	0	41	G
215	5.7	9.4	0	70	0	36	G
230	5.3	10.4	5	95	2	48	
245	4.6	10.5	9	78	3	40	
300	4.3	11.4	11	106	4	54	
315	4.7	11	10	110	3	56	
330	5.1	10.6	9	113	3	58	
345	5.1	10.8	10	112	4	57	
400	5.2	10.6	9	112	3	57	
415	5.3	10.4	6	103	2	53	
430	5.6	10.3	6	99	2	51	
445	5.7	9.5	10	65	4	33	
500	5.2	9.8	10	63	4	32	
515	5.1	9.7	8	63	3	32	
530	5	9.7	4	62	1	32	
545	4.8	9.7	4	62	1	32	
600	4.8	9.4	8	61	3	31	
615	4.9	9.4	9	62	3	32	
630	5.1	9.3	0	63	0	32	G
645	5.2	9.5	1	63	0	32	G
700	5.2	9.4	0	63	0	32	G
715	5.2	9.4	0	63	0	32	G
730	5.2	9.3	0	63	0	32	G
745	5	9.4	0	66	0	34	G
800	5.2	9.4	0	69	0	35	G
815	4.3	10.2	3	80	1	41	
830	4.3	10.8	12	111	4	57	
845	5.5	9.9	14	108	5	55	
900	5.3	9.7	17	100	6	51	
915	5.1	10.2	15	121	5	62	
930	5.1	10.3	10	122	4	62	
945	4.6	11	20	112	7	57	
1000	4.4	11.3	27	105	9	54	
1015	4.1	11.6	28	102	9	52	
1030	4.2	11.4	28	105	9	54	
1045	3.9	11.5	29	101	10	52	
1100	4.2	11.2	29	94	10	48	
1115	4	11.4	29	102	10	52	
1130	3.8	11.8	29	99	9	51	
1145	3.8	12	29	102	9	52	
1200	3.9	11.9	27	102	9	52	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-17-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	3.8	12	28	98	9	50	
1230	3.9	12	25	100	8	51	
1245	3.8	12.1	26	100	8	51	
1300	3.7	12.1	25	99	8	51	
1315	3.8	12	25	101	8	52	
1330	3.8	11.7	30	101	10	52	
1345	2.7	10.2	50	91	15	46	
1400	3.8	11	0	101	0	52	G
1415	3.9	11.5	0	101	0	52	G
1430	4	11.6	0	99	0	51	G
1445	3.8	12.2	0	93	0	47	G
1500	3.4	12.6	0	93	0	47	G
1515	3.5	12.5	0	95	0	48	G
1530	4	12.1	0	87	0	44	G
1545	4.1	12.2	0	98	0	50	G
1600	4	11.7	0	67	0	34	G
1615	3.7	11.5	0	51	0	26	G
1630	3.4	11.6	0	49	0	25	G
1645	3.4	11.6	0	48	0	24	G
1700	3.4	11.6	0	48	0	24	G
1715	3.4	11.6	0	48	0	24	G
1730	3.4	11.7	0	47	0	24	G
1745	3.4	11.7	0	48	0	24	G
1800	3.4	11.7	0	48	0	24	G
1815	3.4	11.6	0	47	0	24	G
1830	3.4	11.7	0	47	0	24	G
1845	2.8	12.6	0	71	0	36	G
1900	3.3	12.4	0	89	0	45	G
1915	3.3	12.5	0	95	0	48	G
1930	3.4	12.6	0	97	0	49	G
1945	3.8	12.3	0	100	0	51	G
2000	3.9	12.2	0	101	0	52	G
2015	4.1	11.3	0	76	0	39	G
2030	3.2	11.4	0	49	0	25	G
2045	3.5	11.2	0	50	0	26	G
2100	3.4	11.3	0	48	0	24	G
2115	3.3	11.4	0	48	0	24	G
2130	3.2	11.7	0	47	0	24	G
2145	3.1	11.8	0	47	0	24	G
2200	3.4	11.6	0	48	0	24	G
2215	3.6	11.6	0	57	0	29	G
2230	3.9	11.6	0	63	0	32	G
2245	4	11.5	0	64	0	33	G
2300	4	11.5	0	62	0	32	C
2315	0	0	0	0	0	0	G
2330	0	0	0	0	0	0	G
2345	4	10.4	0	61	0	31	G
2400	4	10	6	56	2	29	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-18-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	4	10.3	3	55	1	28	
30	4	10.7	1	58	0	30	
45	4	10.8	1	58	0	30	
100	3.6	11.7	2	90	1	46	
115	4	11	2	74	1	38	
130	3.7	11	3	66	1	34	
145	3.8	11.5	3	91	1	46	
200	4.3	11	2	87	1	44	
215	4.1	10.6	2	54	1	28	
230	3.9	10.7	2	51	1	26	
245	3.9	11	1	61	0	31	
300	3.9	11.4	2	77	1	39	
315	4.3	10.8	2	60	1	31	
330	3.9	11.3	2	84	1	43	
345	3.9	11.3	1	98	0	50	
400	3.9	11.3	1	104	0	53	
415	4.1	11.2	1	104	0	53	
430	3.9	11.7	2	105	1	54	
445	4.5	10.8	1	79	0	40	
500	4	10.9	0	64	0	33	
515	3.8	10.7	2	55	1	28	
530	3.6	10.9	2	52	1	27	
545	3.5	11.2	3	59	1	30	
600	3.4	11.6	3	75	1	38	
615	3.5	11.9	0	102	0	52	
630	4	11.5	0	97	0	49	
645	4	10.8	0	66	0	34	
700	3.8	11	0	62	0	32	G
715	3.7	11	0	55	0	28	G
730	3.7	11	1	56	0	29	
745	3.7	10.9	0	57	0	29	
800	3.1	11.4	9	96	3	49	C
815	3.6	10.3	14	94	5	48	
830	3.4	10.8	20	100	6	51	
845	3.7	11	22	104	7	53	
900	2.6	11.8	23	86	7	44	
915	2.4	12.3	22	95	7	48	
930	1.7	12.8	24	79	7	40	
945	1.7	12.6	21	78	6	40	
1000	1.7	12.6	19	78	6	40	
1015	1.8	12.5	19	80	6	41	
1030	1.7	12.6	18	78	5	40	
1045	1.7	12.3	20	77	6	39	
1100	1.7	12.2	28	78	8	40	
1115	1.7	12.2	24	78	7	40	
1130	3.2	10.6	30	60	9	31	
1145	3	11	26	71	8	36	
1200	2.7	11	24	58	7	30	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-18-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	2.7	10.9	24	58	7	30	
1230	3.2	10.7	24	62	8	32	
1245	2.4	11	21	57	6	29	
1300	2.7	10.7	30	59	9	30	
1315	2.3	11.4	33	85	10	43	
1330	2.2	11.5	26	75	8	38	
1345	1.7	11.3	25	41	7	21	
1400	1.5	11.4	24	35	7	18	
1415	2.1	11.1	25	46	7	23	
1430	2.1	10.8	23	47	7	24	
1445	2.2	11.3	22	56	7	29	
1500	2.6	10.9	23	53	7	27	
1515	2.3	11.1	22	52	7	27	
1530	2.8	10.9	20	54	6	28	
1545	4	10.3	17	61	6	31	C
1600	3.9	10.1	13	61	4	31	
1615	3.8	10.1	14	61	5	31	
1630	4	9.6	15	68	5	35	
1645	3	10.9	13	118	4	60	
1700	4	10.5	13	111	4	57	
1715	3.5	10.8	11	124	4	63	
1730	4.4	9.4	17	72	6	37	
1745	3.7	9.9	21	86	7	44	
1800	3.2	10.8	21	122	7	62	
1815	3.8	10.7	17	129	6	66	
1830	3.9	10.5	16	136	5	69	
1845	4.1	10.6	16	141	5	72	
1900	4.3	10.5	18	139	6	71	
1915	4.4	10.6	18	140	6	71	
1930	4.3	10.6	18	139	6	71	
1945	4.4	10.4	16	138	5	70	
2000	4.5	10.3	14	139	5	71	
2015	4.5	10.3	17	138	6	70	
2030	4.4	10.4	16	136	5	69	
2045	4.5	10.4	16	139	5	71	
2100	4.6	10.2	16	141	5	72	
2115	4.6	10.3	15	140	5	71	
2130	4.6	9.9	15	142	5	72	
2145	4.9	9.7	16	144	6	73	
2200	4.9	9.7	16	145	6	74	
2215	4.9	10	13	143	5	73	C
2230	4.6	10.4	10	137	3	70	
2245	4.3	10.8	10	133	3	68	
2300	4.1	10.7	9	132	3	67	
2315	4.1	10.5	8	133	3	68	
2330	4.1	10.6	9	135	3	69	
2345	4.2	10.4	9	137	3	70	
2400	4.1	10.5	9	135	3	69	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-19-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	4.1	10.4	9	134	3	68	
30	4.2	10.5	10	133	3	68	
45	4.2	10.5	11	135	4	69	
100	4.1	10.5	11	134	4	68	
115	4	10.4	9	133	3	68	
130	3.8	10.5	8	131	3	67	
145	3.8	10.4	10	130	3	66	
200	3.8	10.5	10	130	3	66	
215	3.9	10.6	9	131	3	67	
230	3.8	10.7	10	128	3	65	
245	4	10.8	9	131	3	67	
300	3.8	10.9	9	125	3	64	
315	3.9	10.9	7	125	2	64	
330	4	10.8	8	131	3	67	
345	3.9	10.7	7	131	2	67	
400	3.8	10.7	9	127	3	65	
415	3.9	10.7	7	129	2	66	
430	3.9	10.6	8	128	3	65	
445	3.8	10.6	9	126	3	64	
500	3.8	10.6	8	125	3	64	
515	3.8	10.6	9	127	3	65	
530	3.9	10.6	8	129	3	66	
545	3.8	10.5	9	128	3	65	
600	3.8	10.4	11	128	4	65	
615	4.3	9.6	9	94	3	48	
630	3.9	9.5	9	63	3	32	
645	3.5	9.8	10	60	3	31	
700	3.5	9.9	10	59	3	30	
715	3.4	10	9	62	3	32	
730	3.3	10.8	10	97	3	49	
745	3.6	10.4	11	82	4	42	
800	3.7	10.6	11	100	4	51	
815	3.8	10.7	11	110	4	56	
830	4.1	10.2	9	83	3	42	
845	3.9	10.1	10	62	3	32	
900	3.7	10.4	13	60	4	31	
915	4.1	10.2	12	62	4	32	
930	3.7	10.6	10	60	3	31	
945	3.6	10.7	8	59	3	30	
1000	3.6	10.8	5	60	2	31	
1015	3.7	10.7	3	60	1	31	C
1030	0	0	0	0	0	0	C
1045	0	0	0	0	0	0	C
1100	0	0	0	0	0	0	C
1115	3.8	10	22	63	7	32	
1130	3.7	10.3	22	63	7	32	
1145	3.8	10.3	25	63	8	32	
1200	3.7	10.4	24	63	8	32	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-19-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	3.8	10.1	22	64	7	33	
1230	3.7	10.3	22	63	7	32	
1245	3.7	10.3	19	63	6	32	
1300	3.7	10.2	26	63	8	32	
1315	3.8	10.2	26	64	8	33	
1330	3.7	10.5	27	64	9	33	
1345	3.8	10.5	29	65	9	33	
1400	3.7	10.5	27	63	9	32	
1415	3.6	10.4	27	63	9	32	
1430	3.7	10.5	24	64	8	33	
1445	3.8	10.4	20	64	7	33	
1500	3.8	10.5	21	64	7	33	
1515	3.6	10.6	17	62	5	32	
1530	3.6	10.7	25	62	8	32	
1545	3.7	10.5	34	64	11	33	
1600	3.7	10.5	16	64	5	33	C
1615	3.6	10.4	35	63	11	32	
1630	3.6	10.4	37	63	12	32	
1645	3.6	10.3	39	64	13	33	
1700	3.6	10.4	34	63	11	32	
1715	3.6	10.4	38	63	12	32	
1730	3.6	10.3	39	63	13	32	
1745	3.4	10.4	34	62	11	32	
1800	3.4	10.4	36	62	11	32	
1815	3.3	10.3	39	62	12	32	
1830	3.4	10.4	45	63	14	32	
1845	3.1	11.3	45	100	14	51	
1900	3.4	11.1	44	101	14	52	
1915	3.6	10.6	45	65	15	33	
1930	3.4	10.8	43	65	14	33	
1945	3.4	10.9	41	69	13	35	
2000	3.4	10.8	47	70	15	36	
2015	3.4	10.8	44	66	14	34	
2030	3.3	10.7	47	60	15	31	
2045	3.1	10.9	37	64	12	33	
2100	3.2	11	43	69	14	35	
2115	3.3	10.9	47	71	15	36	
2130	3.3	10.9	47	70	15	36	
2145	3.5	10.8	42	68	13	35	
2200	3.3	10.9	32	75	10	38	C
2215	3.4	10.6	24	72	8	37	
2230	3.6	10.3	18	66	6	34	
2245	3.4	10.5	20	64	6	33	
2300	3.3	10.5	21	70	7	36	
2315	3.4	10.6	23	65	7	33	
2330	3.3	10.7	25	61	8	31	
2345	3.2	10.8	14	65	4	33	
2400	3.3	10.7	11	62	3	32	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-20-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	3.3	10.6	22	60	0	0	
30	3.2	10.6	24	59	8	30	
45	3.2	10.6	24	59	8	30	
100	3.2	10.7	24	59	8	30	
115	3.2	10.7	24	58	8	30	
130	3.2	10.8	22	61	7	31	
145	3.3	11	19	72	6	37	
200	3.4	10.8	17	73	5	37	
215	3.6	10.7	12	71	4	36	
230	3.4	10.9	10	83	3	42	
245	3.5	10.8	15	85	5	43	
300	3.8	10.5	13	75	4	38	
315	3.6	10.7	10	77	3	39	
330	3.6	10.8	15	72	5	37	
345	3.5	10.9	33	73	11	37	
400	3.6	10.8	34	70	11	36	
415	3.4	10.7	27	64	9	33	
430	3.5	10.8	25	68	8	35	
445	3.6	10.5	26	64	8	33	
500	3.5	10.6	34	63	11	32	
515	3.6	10.3	32	61	10	31	
530	3.6	10.2	37	65	12	33	
545	3.6	10.2	38	74	12	38	
600	3.7	10.2	31	70	10	36	
615	3.7	10.2	30	78	10	40	
630	3.6	10.5	30	82	10	42	
645	3.7	10.5	30	75	10	38	
700	3.7	10.3	29	67	9	34	
715	3.6	10.4	32	65	10	33	
730	3.7	10.4	31	63	10	32	
745	3.3	10.7	34	72	11	37	
800	3.9	10.2	34	68	11	35	C
815	3.8	10.1	32	63	10	32	
830	3.7	10.2	38	62	12	32	
845	3.6	10.2	38	62	12	32	
900	3.6	10.3	34	61	11	31	
915	3.5	10.3	32	61	10	31	
930	3.5	10.3	32	60	10	31	
945	3.5	10.4	31	60	10	31	
1000	3.4	10.4	31	60	10	31	
1015	3.5	10.2	32	61	10	31	
1030	3.5	10.4	30	61	10	31	
1045	3.5	10.5	30	61	10	31	
1100	3.4	10.4	31	60	10	31	
1115	3.4	10.6	31	59	10	30	
1130	3.4	10.7	31	60	10	31	
1145	3.3	10.8	31	66	10	34	
1200	3.5	10.5	30	62	10	32	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-20-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	3.4	10.6	29	61	9	31	
1230	3.4	10.7	28	61	9	31	
1245	3.3	10.8	27	60	9	31	
1300	3.3	10.8	23	60	7	31	
1315	3.3	10.9	21	60	7	31	
1330	3.1	10.9	22	59	7	30	
1345	3.1	11	19	59	6	30	
1400	3	11	19	60	6	31	
1415	3	11	17	59	5	30	
1430	3	10.9	22	59	7	30	
1445	3	10.7	20	59	6	30	
1500	3.1	10.9	19	59	6	30	
1515	2.9	11	17	57	5	29	
1530	3.1	11	38	58	12	30	
1545	3.1	11	39	69	12	35	
1600	3.2	10.8	38	64	12	33	C
1615	3.1	11.2	38	82	12	42	
1630	3.2	10.6	37	74	12	38	
1645	2.9	11.3	35	101	11	52	
1700	3.2	11.4	30	117	9	60	
1715	3.4	11.6	27	122	9	62	
1730	3.9	10.9	29	99	10	51	
1745	3.6	11.1	35	99	11	51	
1800	3.6	10.8	32	77	10	39	
1815	2.9	11.6	28	84	9	43	
1830	3.1	11.3	24	78	8	40	
1845	2.8	11.8	21	87	6	44	
1900	3.2	11.6	35	100	11	51	
1915	3.8	11.1	35	98	11	50	
1930	2.5	11.7	34	80	10	41	
1945	2.9	12	26	114	8	58	
2000	3.3	11.7	22	121	7	62	
2015	3.2	11.7	150	121	47	62	
2030	3.2	11.8	25	128	8	65	
2045	3.2	12	25	128	8	65	
2100	3.1	12.1	23	119	7	61	
2115	3	11.3	27	79	8	40	
2130	2.9	11.5	34	80	11	41	
2145	3.1	11.5	35	80	11	41	
2200	2.4	12	30	83	9	42	C
2215	2.7	12	33	98	10	50	
2230	3	11.9	30	106	9	54	
2245	3.1	11.1	34	62	11	32	
2300	2.7	11.6	39	81	12	41	
2315	2.8	11.5	43	91	13	46	
2330	3.4	10.8	44	80	14	41	
2345	3.1	10.6	44	60	14	31	
2400	3	10.5	44	62	14	32	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-21-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	3.2	10.2	41	61	13	31	
30	3.2	10.3	40	66	13	34	
45	3.2	10.7	42	81	13	41	
100	3.1	11.4	40	106	13	54	
115	3.2	11.3	40	92	13	47	
130	3.3	11.3	37	92	12	47	
145	3.2	11.5	35	94	11	48	
200	2.9	12	31	119	10	61	
215	3.7	11.1	30	98	10	50	
230	3.1	11.6	28	105	9	54	
245	3.4	11.4	27	122	9	62	
300	3.4	11.5	30	123	10	63	
315	3.3	11.5	29	125	9	64	
330	3.5	11.4	27	127	9	65	
345	3.7	11.3	35	124	11	63	
400	3.7	11	36	108	12	55	
415	3.7	11	36	101	12	52	
430	3.6	11	35	94	11	48	
445	3.3	11.1	35	98	11	50	
500	3.6	10.9	32	106	10	54	
515	3.6	10.8	30	106	10	54	
530	3.4	10.8	29	100	9	51	
545	3.5	11	35	108	11	55	
600	3.7	10.8	34	88	11	45	
615	3.5	10.9	34	85	11	43	
630	3.6	11	34	97	11	49	
645	3.2	11	36	93	11	47	
700	3.2	10.9	33	90	10	46	
715	3.4	11	33	96	11	49	
730	3.4	11	32	92	10	47	
745	3.2	11	31	81	10	41	
800	3.3	11.3	30	98	10	50	
815	3.2	11.5	28	111	9	57	
830	3.6	10.9	32	80	10	41	
845	2.6	12	34	113	10	58	
900	3.6	10.6	42	78	14	40	C
915	2.4	10.4	154	58	47	30	
930	2.9	10.6	11	59	3	30	
945	2.7	10.6	14	56	4	29	
1000	2.7	10.6	13	59	4	30	
1015	2.6	10.4	11	58	3	30	
1030	2.6	10.5	15	63	5	32	
1045	2.5	10.6	9	61	3	31	
1100	2.6	10.7	13	67	4	34	
1115	2.4	10.9	14	87	4	44	
1130	2.1	10.6	14	78	4	40	
1145	1.5	10.8	11	63	3	32	
1200	1.9	10.5	8	54	2	28	C

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-21-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	1.8	10.8	8	50	2	26	
1230	1.8	11	7	51	2	26	
1245	1.6	11.2	10	51	3	26	
1300	2	11.7	10	54	3	28	
1315	2	11.4	12	56	4	29	
1330	2.1	11.5	9	54	3	28	
1345	2	11.7	10	53	3	27	
1400	2.1	11.4	11	53	3	27	
1415	2.3	11.3	11	54	3	28	
1430	2	12.3	226	84	67	43	C
1445	2.2	11.8	14	76	4	39	
1500	3.6	10.8	44	97	14	49	
1515	3.9	10.8	2	83	1	42	
1530	4.3	10.3	10	73	3	37	
1545	4.1	10.6	10	71	3	36	
1600	3.7	11.4	11	113	4	58	
1615	4.3	10.5	10	75	3	38	
1630	3.7	11.2	11	97	4	49	
1645	4.2	10.7	12	80	4	41	
1700	4.3	10.3	10	72	3	37	
1715	4.2	10.2	10	67	3	34	
1730	4	10.3	10	71	3	36	
1745	4.2	10.2	8	64	3	33	
1800	4.1	10.3	8	64	3	33	
1815	4.2	10.5	8	65	3	33	
1830	4.2	10.6	8	65	3	33	
1845	4.2	10.6	7	65	2	33	
1900	4.2	10.5	9	64	3	33	
1915	4.2	10.3	9	64	3	33	
1930	4.2	10.3	6	63	2	32	
1945	4.1	10.6	3	71	1	36	
2000	4.1	10.9	7	86	2	44	
2015	4.5	10.5	8	71	3	36	
2030	4.3	10.6	8	74	3	38	
2045	4.4	10.6	7	81	2	41	
2100	4.2	10.9	5	85	2	43	
2115	4.4	10.7	7	87	2	44	
2130	4.4	10.5	6	89	2	45	
2145	4.5	10.2	6	74	2	38	
2200	4.6	10.2	6	80	2	41	
2215	4.4	10.3	6	76	2	39	
2230	4.5	10.4	8	80	3	41	
2245	4.1	10.8	11	86	4	44	
2300	4.2	10.8	9	94	3	48	
2315	4.3	10.8	10	93	3	47	
2330	4.7	10.3	10	72	3	37	
2345	4.4	10.7	11	85	4	43	
2400	4.7	10	11	69	0	35	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-22-1983
LOAD 11500 BBL/D

15 MIN DATA
DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	4.6	10.3	11	66	4	34	
30	4.2	10.7	9	73	3	37	
45	4.4	10.8	9	89	3	45	
100	4.3	11	8	94	3	48	
115	4.4	11	9	105	3	54	
130	4.7	10.7	10	99	3	51	
145	4.8	10.4	9	84	3	43	
200	4.8	10.6	6	91	2	46	
215	4.7	10.5	3	81	1	41	
230	4.2	11	8	106	3	54	
245	4.3	11.3	10	124	3	63	
300	4.6	11.2	10	128	3	65	
315	4.6	11.3	9	126	3	64	
330	5	10.7	9	107	3	55	
345	4.6	11.3	8	121	3	62	
400	4.8	11	6	114	2	58	
415	5.1	10.3	4	83	1	42	
430	4.4	10.9	7	94	2	48	
445	4.6	10.8	9	89	3	45	
500	4.5	11.1	9	115	3	59	
515	4.9	10.8	4	105	1	54	
530	4.4	11.1	3	103	1	53	
545	4.7	11.1	5	113	2	58	
600	4.9	10.8	8	107	3	55	
615	4.6	10.9	8	104	3	53	
630	4.8	10.9	8	106	3	54	
645	4.7	10.7	9	93	3	47	
700	5	10.7	6	105	2	54	
715	4.6	10.9	4	101	1	52	
730	4.6	10.8	8	103	3	53	
745	4.9	10.6	8	102	3	52	
800	4.5	11	8	110	3	56	
815	4.8	10.9	7	112	2	57	
830	4.6	11.1	7	112	2	57	
845	4.8	10.9	7	111	2	57	
900	4.6	11.1	0	102	0	52	
915	4.4	11.4	0	118	0	60	G
930	4.6	11.3	0	127	0	65	G
945	4.6	11.3	0	120	0	61	G
1000	4.7	11.1	0	115	0	59	G
1015	5	10.9	0	122	0	62	G
1030	0	0	0	0	0	0	C
1045	0	0	0	0	0	0	C
1100	1.9	11.7	2	92	1	47	
1115	1.8	11.6	1	93	0	47	
1130	2.1	11.5	5	104	1	53	
1145	2.4	11.5	6	106	2	54	
1200	2.4	11.4	1	107	0	55	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-22-1983
LOAD 11500 BBL/D

15 MIN DATA
DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	2.2	11.5	0	111	0	57	
1230	0	0	0	0	0	0	C
1245	0	0	0	0	0	0	C
1300	1.8	11.9	3	101	1	52	
1315	0	0	0	0	0	0	C
1330	2.1	11.9	3	108	1	55	
1345	2.1	11.7	2	107	1	55	
1400	2	11.8	1	105	0	54	
1415	2.1	11.6	12	109	4	56	
1430	2	11.7	33	107	10	55	
1445	2.3	11.5	3	110	1	56	
1500	2.3	11.5	6	102	2	52	
1515	2	11.6	2	93	1	47	
1530	2.1	11.8	0	101	0	52	
1545	2.4	11.1	7	69	2	35	
1600	2.4	11	11	61	3	31	
1615	1.9	11.5	13	52	4	27	
1630	1.7	11.7	99	55	29	28	
1645	1.3	11.9	89	53	25	27	
1700	1.8	11.8	100	73	29	37	
1715	3.1	11.5	9	96	3	49	
1730	3.4	11.3	12	89	4	45	
1745	3.1	11.4	12	90	4	46	
1800	2.9	11.9	13	107	4	55	
1815	3.3	11.7	12	115	4	59	
1830	3.1	11.8	13	113	4	58	
1845	3.2	11.8	12	114	4	58	
1900	3.3	11.6	6	113	2	58	
1915	3.3	11.7	3	111	1	57	
1930	0	0	0	0	0	0	C
1945	3.4	11.3	16	88	5	45	
2000	3.2	11.4	10	91	3	46	
2015	3.4	10.7	1	74	0	38	
2030	3.5	10.5	3	65	1	33	
2045	3.1	10.9	1	65	0	33	
2100	3.2	10.5	2	64	1	33	
2115	3.5	10.4	7	60	2	31	
2130	3.5	10.3	7	58	2	30	
2145	3.3	10.4	7	60	2	31	
2200	3.3	10.1	0	58	0	30	G
2215	3.3	10.1	0	59	0	30	G
2230	3.4	10.2	0	59	0	30	G
2245	3.3	10.5	0	57	0	29	G
2300	3.4	10.4	0	56	0	29	G
2315	3.4	10.5	0	56	0	29	G
2330	3.4	10.5	0	57	0	29	G
2345	3.1	10.8	0	61	0	31	G
2400	3.4	10.7	0	57	0	29	G

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-23-1983　　15 MIN DATA
LOAD 11500 BBL/D　　DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	3.4	10.4	0	56	0	29	G
30	3.5	10.3	0	57	0	29	G
45	3.6	10.1	0	57	0	29	G
100	3.8	10.2	0	59	0	30	G
115	4.1	10.1	0	59	0	30	G
130	4.4	9.9	0	61	0	31	G
145	2.9	11	0	62	0	32	G
200	3	10.7	0	55	0	28	G
215	3.2	10.4	0	55	0	28	G
230	3.3	10.3	0	56	0	29	G
245	3.3	10.4	0	59	0	30	G
300	3.2	10.6	0	56	0	29	G
315	3	10.8	0	55	0	28	G
330	2.8	11	0	54	0	28	G
345	3	10.9	0	55	0	28	G
400	3.1	10.8	0	55	0	28	G
415	3.1	10.7	0	54	0	28	G
430	3.2	10.5	0	55	0	28	G
445	3.3	10.7	0	60	0	31	G
500	3.4	11	0	91	0	46	G
515	3	11.4	0	93	0	47	G
530	3.3	10.6	0	56	0	29	G
545	3.3	10.7	0	56	0	29	G
600	3.5	10.6	0	67	0	34	G
615	4.4	9.9	0	60	0	31	G
630	4.2	10	0	60	0	31	G
645	3.9	10.2	0	59	0	30	G
700	3.8	10.2	0	58	0	30	G
715	3.6	10.3	0	57	0	29	G
730	3.4	10.4	0	56	0	29	G
745	3.4	10.5	0	55	0	28	G
800	3.3	10.4	0	55	0	28	G
815	3.2	10.4	0	57	0	29	G
830	3.5	10.4	0	68	0	35	G
845	3.8	10.3	0	63	0	32	G
900	3.4	10.2	0	57	0	29	C
915	2.4	10.6	22	50	7	26	
930	1.9	10.4	21	46	6	23	
945	2	10.6	25	48	7	24	
1000	1.9	10.9	22	48	6	24	
1015	1.8	11.1	25	48	7	24	
1030	1.8	11.2	26	48	8	24	
1045	1.9	11	26	49	8	25	
1100	1.9	11	32	48	9	24	
1115	1.9	10.8	63	62	19	32	C
1130	2	10.7	4	49	1	25	
1145	2	11	3	56	1	29	
1200	2	11.4	3	50	1	26	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-23-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	2	11.6	3	50	1	26	
1230	1.9	11.5	0	51	0	26	G
1245	1.8	11.6	3	49	1	25	
1300	1.7	11.5	6	49	2	25	
1315	1.8	11.4	6	49	2	25	
1330	1.9	11.5	6	51	2	26	
1345	2	11.6	7	52	2	27	
1400	2	11.6	5	53	1	27	
1415	2	11.7	6	54	2	28	
1430	2.1	11.5	7	55	2	28	
1445	2.1	11.3	5	55	1	28	
1500	2.1	11.4	3	55	1	28	
1515	2.1	11.6	3	53	1	27	
1530	2.2	11.5	7	53	2	27	
1545	2.3	11.6	6	54	2	28	
1600	2.1	12	3	78	1	40	
1615	2.5	11.5	0	56	0	29	G
1630	2.5	11.5	0	66	0	34	G
1645	2.8	11.3	0	57	0	29	G
1700	2.7	11.3	0	55	0	28	G
1715	2.4	11.4	0	53	0	27	
1730	2.5	11.3	0	54	0	28	
1745	2.4	11.3	0	53	0	27	
1800	2.4	11.5	1	54	0	28	
1815	2.5	11.6	2	54	1	28	
1830	2.4	11.6	0	64	0	33	G
1845	2.5	11.5	0	54	0	28	G
1900	1.5	12.5	0	75	0	38	G
1915	2.7	11.4	0	73	0	37	G
1930	2.6	11.4	0	53	0	27	G
1945	1.5	12.4	0	62	0	32	G
2000	2.9	11	0	57	0	29	G
2015	2.7	11.2	0	55	0	28	G
2030	2	12.1	5	82	1	42	
2045	1.6	12.5	267	100	77	51	
2100	1.4	12.7	494	91	142	46	
2115	2.8	11.6	0	125	0	64	
2130	2.9	11.7	12	139	4	71	
2145	3.3	11.4	11	144	3	73	
2200	3.1	11.5	5	145	2	74	
2215	2.9	11.7	1	137	0	70	
2230	3.6	10.9	4	109	1	56	
2245	3.3	10.8	6	72	2	37	
2300	3	10.8	5	58	2	30	
2315	2.5	11	35	64	11	33	
2330	2.7	10.9	6	57	2	29	
2345	2.1	11.5	6	52	2	27	
2400	2.2	11.4	7	52	2	27	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-24-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	2.2	11.6	6	53	2	27	
30	2.2	11.6	6	60	2	31	
45	2.4	11.3	7	57	2	29	
100	2.4	11.2	5	52	2	27	
115	2.3	11.4	1	73	0	37	
130	2.4	11.5	1	81	0	41	
145	2.4	11.6	0	83	0	42	
200	2.5	11.6	2	86	1	44	
215	2.6	11.5	2	94	1	48	
230	2	12.3	5	130	1	66	
245	2.2	12.1	9	149	3	76	
300	2.6	11.7	9	158	3	81	
315	3.1	11.4	8	165	3	84	
330	3.1	11.6	9	166	3	85	
345	2.9	11.8	9	157	3	80	
400	3	11.9	9	161	3	82	
415	3	11.7	6	163	2	83	
430	2.9	11.7	4	160	1	82	
445	2.7	12	8	155	2	79	
500	3	11.7	4	159	1	81	
515	3	11.6	3	159	1	81	
530	3.4	11.5	6	166	2	85	
545	3.3	11.6	8	166	3	85	
600	3.2	11.6	7	162	2	83	
615	3	11.7	7	155	2	79	
630	2.9	11.9	6	155	2	79	
645	3.1	11.2	1	140	0	71	
700	2.9	10.9	4	93	1	47	
715	2.9	11.7	2	125	1	64	
730	2.8	11.9	5	132	2	67	
745	3	11.7	7	142	2	72	
800	3.3	11.3	9	129	3	66	
815	3.3	11	8	70	3	36	
830	2.9	11	5	61	2	31	
845	2.7	11	3	57	1	29	
900	2.6	11.1	2	56	1	29	
915	2.5	11.2	8	55	2	28	
930	2.4	11.3	10	54	3	28	
945	2.4	11.4	11	52	3	27	
1000	2.3	11.9	142	61	43	31	
1015	2.6	11.3	7	54	2	28	C
1030	2.3	10.5	3	52	1	27	
1045	1.9	11.1	5	50	1	26	
1100	2	10.9	6	52	2	27	
1115	2.1	11	3	53	1	27	
1130	2	11.3	1	72	0	37	
1145	2	11	0	55	0	28	G
1200	1.8	11.2	0	55	0	28	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-24-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	2	11	0	52	0	27	G
1230	1.9	10.6	1	51	0	26	
1245	1.9	10.6	11	51	3	26	
1300	1.7	10.7	13	50	4	26	
1315	2	11.2	6	67	2	34	
1330	2.2	11.6	20	100	6	51	
1345	2.3	11.3	9	100	3	51	C
1400	2	11.6	4	100	1	51	
1415	2.3	10.9	6	64	2	33	
1430	1.8	11.4	5	94	1	48	
1445	1.9	11.5	2	105	1	54	
1500	2.2	11.3	0	112	0	57	
1515	2	11.3	0	112	0	57	G
1530	2.1	11.3	0	112	0	57	G
1545	2.1	11.3	10	111	3	57	
1600	3	10.8	16	115	5	59	
1615	2.3	11.2	19	118	6	60	
1630	1.7	11.7	21	119	6	61	
1645	2.2	11.4	22	131	7	67	
1700	2.2	11.5	21	133	6	68	
1715	3.2	11	23	141	7	72	
1730	3.3	10.7	23	111	7	57	
1745	2.3	11.6	23	110	7	56	
1800	2.5	11.5	26	123	8	63	
1815	2.7	11.3	29	129	9	66	
1830	2.5	11.2	31	128	9	65	
1845	2.9	11.1	27	134	8	68	
1900	3.1	11.2	25	133	8	68	
1915	3	11.3	29	130	9	66	
1930	2.9	11.4	26	124	8	63	
1945	3	11.2	24	123	8	63	
2000	2.9	11.2	28	127	9	65	
2015	2.9	11.1	28	130	9	66	
2030	2.8	11	26	129	8	66	
2045	2.8	11.1	21	128	6	65	
2100	2.8	11.2	28	123	9	63	
2115	2.8	11.2	31	122	10	62	
2130	2.8	11.1	24	125	7	64	
2145	2.8	11.2	29	129	9	66	
2200	2.7	11.1	30	129	9	66	
2215	2.8	11.1	28	135	9	69	
2230	2.6	11.3	29	134	9	68	
2245	2.8	11.3	13	138	4	70	
2300	3.2	11	10	139	3	71	
2315	3.3	10.9	13	138	4	70	
2330	3.1	11.1	29	137	9	70	
2345	3	11.1	38	137	12	70	
2400	2.9	11.1	34	132	11	67	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-25-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	3	11	18	136	6	69	
30	2.6	11.4	25	135	8	69	
45	3.1	11.1	25	138	8	70	
100	2.6	11.5	25	130	8	66	
115	2.8	11.5	22	134	7	68	
130	2.9	11.4	24	134	7	68	
145	2.9	11.2	26	134	8	68	
200	3.1	11.1	26	139	8	71	
215	3	11.2	28	139	9	71	
230	2.9	11.4	24	139	7	71	
245	3	11.4	29	138	9	70	
300	3.2	11.2	37	134	12	68	
315	3.2	11.2	38	128	12	65	
330	3	10.9	39	115	12	59	
345	2.7	11.2	39	119	12	61	
400	2.9	11.1	39	123	12	63	
415	2.8	11.2	34	123	11	63	
430	2.8	11.2	32	124	10	63	
445	3	11.2	32	128	10	65	
500	3	11.2	32	126	10	64	
515	3	10.8	30	104	9	53	
530	2.9	10.7	23	92	7	47	
545	2.9	10.9	23	109	7	56	
600	2.9	11.1	26	118	8	60	
615	3	11.1	25	121	8	62	
630	2.7	11.3	27	121	8	62	
645	2.7	11.3	25	127	8	65	
700	3	11.2	31	132	10	67	
715	3.1	11	26	134	8	68	
730	3.2	10.8	22	135	7	69	
745	3.1	10.8	24	137	8	70	
800	3.1	11	28	140	9	71	
815	3	11.2	27	139	8	71	
830	3.2	10.6	28	92	9	47	
845	2.8	10.9	28	93	9	47	
900	2.6	9.6	8	64	2	33	C
915	1.9	10.5	6	74	2	38	
930	1.8	10.6	5	68	1	35	
945	1.7	10.8	5	67	1	34	
1000	1.7	10.8	5	72	1	37	
1015	1.7	10.5	3	67	1	34	
1030	2.3	10.1	6	62	2	32	
1045	2	10.3	6	55	2	28	
1100	1	10.9	844	51	237	26	
1115	2.2	10.8	123	100	37	51	
1130	2.9	10.3	11	105	3	54	
1145	2.6	10.2	7	84	2	43	
1200	1.8	10.1	6	57	2	29	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-25-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	1.7	10.2	5	57	1	29	
1230	1.5	10.3	6	61	2	31	
1245	.7	11	55	71	15	36	
1300	1.7	10.7	8	95	2	48	
1315	1.8	10.6	6	97	2	49	
1330	2.2	10.7	5	103	1	53	
1345	2.2	10.7	4	103	1	53	
1400	2	10.7	8	102	2	52	
1415	1.6	10.7	9	96	3	49	
1430	1.7	10.7	3	104	1	53	
1445	1.4	11.5	20	90	6	46	C
1500	2.8	11	20	100	6	51	
1515	2.9	9.4	16	83	5	42	
1530	2.6	10.9	17	110	5	56	
1545	3.2	10.5	16	129	5	66	
1600	3.2	10.6	12	131	4	67	
1615	3.4	10.5	26	132	8	67	
1630	3.6	10.3	26	116	8	59	
1645	3.4	10.2	26	107	8	55	
1700	1.1	9.8	326	40	92	20	
1715	.3	9.2	400	13	109	7	
1730	1.8	11.2	179	75	52	38	
1745	3	10.9	41	92	13	47	M
1800	2.9	10.7	43	91	13	46	
1815	4.1	10.2	42	102	14	52	
1830	4.3	9.9	40	103	13	53	
1845	4.1	10.3	40	102	13	52	
1900	4	10.5	38	101	13	52	
1915	4.1	10.6	34	102	11	52	
1930	4	10.5	33	101	11	52	
1945	3.9	10.5	32	99	11	51	
2000	4	10.4	31	100	10	51	C
2015	3.9	10.3	31	99	10	51	
2030	4	10.3	31	101	10	52	
2045	4	10.4	35	102	12	52	
2100	4	10.5	36	100	12	51	
2115	4	10.5	35	99	12	51	
2130	4	10.5	31	98	10	50	
2145	4	10.5	34	97	11	49	
2200	4.1	10.3	38	98	13	50	
2215	4.1	10.4	37	98	12	50	
2230	4.3	10.3	34	101	11	52	
2245	5	9.9	34	105	12	54	
2300	4.4	10.3	31	99	11	51	
2315	5.1	9.9	33	105	12	54	
2330	6	9.4	30	112	11	57	
2345	6.4	9.1	34	114	13	58	
2400	5.9	9.3	30	110	11	56	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-26-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	5.6	9.7	27	106	10	54	
30	5.7	9.4	27	104	10	53	
45	5.6	9.4	27	101	10	52	
100	5.4	9.6	27	100	10	51	
115	5.5	9.5	27	101	10	52	
130	5.5	9.4	25	103	9	53	
145	5.6	9.3	24	104	9	53	
200	5.5	9.6	24	104	9	53	
215	5.5	9.9	21	105	8	54	
230	5.3	9.9	21	104	8	53	
245	5.4	9.8	21	104	8	53	
300	5.4	9.7	19	105	7	54	
315	5.4	9.8	22	104	8	53	
330	5.4	9.6	21	103	8	53	
345	5.6	9.7	21	106	8	54	
400	5.5	9.8	24	105	9	54	
415	5.2	10	32	103	11	53	
430	5.2	10	37	102	13	52	
445	5	10.1	39	101	14	52	
500	5.1	10	39	101	14	52	
515	4.9	10	39	99	14	51	
530	5.2	10	39	103	14	53	
545	5.2	10.1	38	103	14	53	
600	5.1	10.1	39	102	14	52	
615	5.1	10.1	38	102	13	52	
630	5	10.1	37	100	13	51	
645	4.9	10.2	31	98	11	50	
700	5.1	10.1	31	100	11	51	
715	5	10.1	32	99	11	51	
730	4.9	10.1	33	100	12	51	
745	5	10.4	33	103	12	53	
800	5	10.9	33	106	12	54	
815	4.8	10.7	33	104	11	53	
830	4.8	10.7	36	105	13	54	
845	4.6	10.8	32	104	11	53	
900	4.8	10.6	33	106	11	54	C
915	4.6	10.7	32	105	11	54	
930	4.6	10.5	35	107	12	55	
945	4.6	10.5	39	109	13	56	
1000	4.7	10.4	39	110	13	56	
1015	4.6	10.6	35	107	12	55	
1030	4.6	10.5	38	112	13	57	
1045	4.7	10.6	31	112	11	57	
1100	4.8	10.4	30	112	10	57	
1115	4.7	10.5	34	111	12	57	
1130	4.6	10.3	33	111	11	57	
1145	4.6	10.6	33	112	11	57	
1200	4.5	10.4	33	110	11	56	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-26-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	4.5	10.8	33	111	11	57	
1230	4.4	10.5	32	111	11	57	
1245	4.3	10.5	32	111	11	57	
1300	4.4	10.4	33	114	11	58	
1315	4.5	10.5	33	115	11	59	
1330	4.5	10.2	32	115	11	59	
1345	4.4	10.5	31	116	11	59	
1400	4.6	10.2	31	116	11	59	
1415	4.5	10.5	31	115	11	59	
1430	4.5	10.2	31	115	11	59	
1445	4.5	10.3	32	115	11	59	
1500	4.5	10	31	116	11	59	
1515	4.5	10.5	30	115	10	59	
1530	4.5	10.2	28	115	10	59	
1545	4.5	10.5	23	113	8	58	
1600	4.5	10.5	22	114	8	58	C
1615	4.4	10.6	25	112	8	57	
1630	4.5	10.5	29	115	10	59	
1645	4.4	10.5	33	115	11	59	
1700	4.4	10.5	36	115	12	59	
1715	4.3	10.3	38	110	13	56	
1730	4.2	10.4	39	110	13	56	
1745	4.4	10.4	33	110	11	56	
1800	4.2	10.3	24	109	8	56	
1815	4.3	10.3	25	110	8	56	
1830	4.3	10.3	33	109	11	56	
1845	4.3	10.4	36	108	12	55	
1900	4.3	10.3	35	106	12	54	
1915	4.3	10.3	34	107	11	55	
1930	4.4	10.4	40	107	14	55	
1945	4.4	10.4	37	106	13	54	
2000	4.4	10.3	28	108	9	55	C
2015	4.4	10.6	25	110	8	56	
2030	4.3	10.6	26	108	9	55	
2045	4	10.9	20	104	7	53	
2100	4	10.8	24	105	8	54	
2115	4	10.7	25	104	8	53	
2130	4.4	10.3	20	108	7	55	
2145	4	10.5	33	105	11	54	
2200	4	10.7	39	105	13	54	
2215	4.1	10.7	38	105	13	54	
2230	3.8	10.7	37	100	12	51	
2245	3.9	10.6	42	101	14	52	
2300	4	10.6	43	101	14	52	
2315	4	10.5	43	102	14	52	
2330	3.9	10.6	44	102	14	52	
2345	4	10.7	43	102	14	52	
2400	3.9	10.7	43	101	14	52	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-27-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	02 VOL% MEAS	C02 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%02	CO NG/J --	NO NG/J --	CODE
15	3.9	10.7	43	101	0	0	
30	3.9	4.7	43	100	14	51	
45	4	0	43	101	14	52	F
100	4	0	43	101	14	52	F
115	3.9	0	44	103	14	53	F
130	3.9	0	44	101	14	52	F
145	4	0	44	101	15	52	F
200	4	0	44	102	15	52	F
215	4	0	44	102	15	52	F
230	4	0	44	100	15	51	F
245	4	0	44	100	15	51	F
300	4	0	44	100	15	51	F
315	3.9	0	44	100	14	51	F
330	3.9	0	44	100	14	51	F
345	3.9	0	44	101	14	52	F
400	4	0	44	101	15	52	F
415	4	0	44	99	15	51	F
430	4	0	44	99	15	51	F
445	4	0	44	99	15	51	F
500	4	0	44	100	15	51	F
515	4	0	44	102	15	52	F
530	4	0	44	102	15	52	F
545	4.1	0	44	102	15	52	F
600	4	0	44	101	15	52	F
615	4	0	44	100	15	51	F
630	4.1	0	44	100	15	51	F
645	4.1	0	44	99	15	51	F
700	4.1	0	44	97	15	49	F
715	4.1	0	44	97	15	49	F
730	4.1	0	44	96	15	49	F
745	4.1	0	44	97	15	49	F
800	4.1	0	44	98	15	50	F
815	4.1	0	44	98	15	50	F
830	4	0	44	98	15	50	F
845	3.5	0	44	94	14	48	F
900	3.4	0	44	95	14	48	C/F
915	3.6	0	44	97	14	49	F
930	3.5	0	44	97	14	49	F
945	3.6	0	44	100	14	51	F
1000	3.6	0	44	100	14	51	F
1015	3.7	0	44	102	14	52	F
1030	3.6	0	43	101	14	52	F
1045	3.6	0	43	100	14	51	F
1100	3.6	0	43	101	14	52	F
1115	3.7	0	43	102	14	52	F
1130	3.6	0	44	102	14	52	F
1145	3.5	0	43	104	14	53	F
1200	3.6	0	44	104	14	53	F

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-27-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	3.6	0	43	103	14	53	F
1230	3.6	0	44	103	14	53	F
1245	3.7	0	43	104	14	53	F
1300	3.6	0	43	103	14	53	F
1315	3.6	0	44	103	14	53	F
1330	3.6	0	43	105	14	54	F
1345	3.5	0	43	104	14	53	F
1400	3.5	0	43	103	14	53	F
1415	3.5	0	43	101	14	52	F
1430	3.6	0	43	101	14	52	F
1445	3.5	0	43	101	14	52	F
1500	3.4	0	43	101	14	52	F
1515	3.5	0	43	101	14	52	F
1530	3.3	0	44	99	14	51	F
1545	3.3	0	43	98	14	50	F
1600	3.3	0	43	99	14	51	F
1615	3.4	0	43	100	14	51	F
1630	3.5	0	43	98	14	50	F
1645	3.4	0	44	97	14	49	F
1700	3.3	0	43	98	14	50	F
1715	3.4	0	43	99	14	51	F
1730	3.4	0	43	98	14	50	C/F
1745	3.3	9.7	8	96	3	49	
1800	3.5	10.7	4	98	1	50	
1815	3.3	10.8	6	96	2	49	
1830	3.3	10.8	8	95	3	48	
1845	3.4	10.7	7	96	2	49	
1900	3.3	10.7	8	96	3	49	
1915	3.4	10.8	11	96	4	49	
1930	3.3	10.8	7	94	2	48	
1945	3.4	10.8	6	95	2	48	
2000	3.4	10.8	6	91	2	46	
2015	3.2	10.7	6	88	2	45	
2030	3.2	10.7	6	87	2	44	
2045	3.3	10.6	6	89	2	45	
2100	3.3	10.8	5	89	2	45	
2115	3.4	10.7	6	88	2	45	
2130	3.4	10.7	6	88	2	45	
2145	3.4	10.8	5	88	2	45	
2200	3.3	10.7	6	87	2	44	
2215	3.2	10.6	6	85	2	43	
2230	3.3	10.6	5	85	2	43	
2245	3.1	10.7	6	84	2	43	
2300	3.2	10.8	6	84	2	43	
2315	3.2	10.8	6	85	2	43	
2330	3.3	10.8	6	85	2	43	
2345	3.2	10.7	6	84	2	43	
2400	3.2	10.7	6	86	2	44	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-28-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	3.2	10.7	6	86	2	44	
30	3.2	10.7	6	86	2	44	
45	3.3	10.8	6	87	2	44	
100	3.3	10.8	6	87	2	44	
115	3.3	10.7	6	87	2	44	
130	3.4	10.6	6	87	2	44	
145	3.4	10.6	6	89	2	45	
200	3.3	10.7	6	88	2	45	
215	3.3	10.8	6	90	2	46	
230	3.4	10.8	6	90	2	46	
245	3.4	10.8	6	89	2	45	
300	3.4	10.8	6	90	2	46	
315	3.6	10.7	6	91	2	46	
330	3.5	10.6	6	91	2	46	
345	3.5	10.7	6	91	2	46	
400	3.4	10.8	7	91	2	46	
415	3.5	10.7	7	92	2	47	
430	3.4	10.8	7	90	2	46	
445	3.5	10.8	7	90	2	46	
500	3.5	10.7	7	90	2	46	
515	3.5	10.7	7	90	2	46	
530	3.5	10.7	7	90	2	46	
545	3.4	10.8	7	89	2	45	
600	3.4	10.8	7	88	2	45	
615	3.3	10.8	7	86	2	44	
630	3.2	10.8	7	86	2	44	
645	3.2	10.7	7	86	2	44	
700	3.2	10.7	7	87	2	44	
715	3.4	10.7	7	89	2	45	
730	3.2	10.8	7	89	2	45	
745	3.1	10.9	7	87	2	44	
800	2.9	10.9	7	86	2	44	
815	1.4	11.3	8	73	2	37	
830	2	11.1	7	79	2	40	
845	3.6	10.6	7	95	2	48	C
900	3.1	10.7	3	92	1	47	
915	2.8	10.8	2	89	1	45	
930	2.4	11.3	3	87	1	44	
945	2.6	11	3	89	1	45	
1000	2.4	11.1	3	87	1	44	
1015	2	11.2	3	83	1	42	
1030	2	11	3	82	1	42	
1045	2	11	3	84	1	43	
1100	1.9	11.1	3	83	1	42	
1115	1.9	11.3	3	83	1	42	
1130	2	11.1	3	83	1	42	
1145	2	11.3	3	83	1	42	
1200	2	11.2	3	82	1	42	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-28-1983　　15 MIN DATA
LOAD 11500 BBL/D　　DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	1.8	11.1	2	81	1	41	
1230	2.1	11.1	2	85	1	43	
1245	2.1	11.2	2	86	1	44	
1300	2	11.2	5	83	1	42	C
1315	2.1	11.1	5	83	1	42	
1330	2.1	11.1	5	82	1	42	
1345	2	11.4	5	81	1	41	
1400	2	11.3	6	81	2	41	
1415	1.6	11.7	7	77	2	39	
1430	1.2	11.8	8	73	2	37	
1445	.9	11.8	155	68	43	35	
1500	1.3	11.7	7	74	2	38	
1515	1.2	11.7	123	70	35	36	
1530	1	11.9	23	69	6	35	
1545	.6	12.3	51	63	14	32	
1600	.5	12.3	115	62	31	32	
1615	.6	12.1	11	64	3	33	
1630	.4	12	95	61	26	31	
1645	.6	11.9	86	63	24	32	
1700	.5	12	56	61	15	31	
1715	.9	11.9	23	67	6	34	
1730	.5	12.3	398	59	109	30	
1745	2.5	10.9	1083	74	328	38	
1800	5.8	9.8	10	116	4	59	
1815	5.7	9.7	7	115	3	59	
1830	5.6	9.8	7	115	3	59	
1845	5.8	9.6	6	116	2	59	
1900	5.6	9.9	6	116	2	59	
1915	5.7	9.8	6	116	2	59	
1930	4.9	10.1	6	107	2	55	
1945	3.8	10.7	9	99	3	51	C
2000	3.7	11.6	12	99	4	51	
2015	3.2	11.9	11	94	3	48	
2030	2.5	12.3	12	87	4	44	
2045	2.4	12.6	11	86	3	44	
2100	2.4	12.3	12	86	4	44	
2115	2.8	12.5	12	87	4	44	
2130	2.7	12.6	12	86	4	44	
2145	2.7	12.7	12	88	4	45	
2200	2.9	12.7	12	88	4	45	
2215	2.6	12.6	12	85	4	43	
2230	2.8	12.6	12	87	4	44	
2245	2.7	12.7	12	87	4	44	
2300	2.9	12.6	13	88	4	45	
2315	3	12.4	13	88	4	45	
2330	2.9	12.6	13	87	4	44	
2345	2.9	12.7	13	87	4	44	
2400	2.9	12.7	13	88	4	45	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-29-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	2.8	12.6	13	87	4	44	
30	2.9	12.6	13	87	4	44	
45	3	12.5	13	88	4	45	
100	3	12.3	13	88	4	45	
115	3	12.3	14	87	4	44	
130	2.9	12.4	13	88	4	45	
145	2.9	12.5	13	88	4	45	
200	2.8	12.5	13	88	4	45	
215	2.7	12.7	13	86	4	44	
230	2.8	12.4	13	85	4	43	
245	2.8	12.4	13	85	4	43	
300	2.8	12.3	14	86	4	44	
315	3.1	12.1	13	89	4	45	
330	3.1	12.3	14	90	4	46	
345	3.3	12.3	13	91	4	46	
400	3.3	12.4	13	90	4	46	
415	3.4	12.4	13	90	4	46	
430	3.3	12.3	13	90	4	46	
445	3.4	12.2	14	90	4	46	
500	3.4	12.4	14	91	4	46	
515	3.6	12.3	13	92	4	47	
530	3.4	12.5	13	91	4	46	
545	3.2	12.6	13	88	4	45	
600	3.3	12.6	13	89	4	45	
615	3.4	12.5	13	90	4	46	
630	3.4	12.4	14	90	4	46	
645	3.4	12.4	15	90	5	46	
700	3.4	12.4	14	91	4	46	
715	3.3	12.6	13	90	4	46	
730	3.3	12.5	13	89	4	45	
745	3.4	12.5	13	91	4	46	
800	3.4	12.5	13	91	4	46	
815	3.3	12.5	13	91	4	46	
830	2.7	12.5	14	87	4	44	C
845	1.4	12.9	202	70	58	36	
900	3.2	12.3	13	91	4	46	
915	1.4	13.4	58	69	17	35	
930	2.5	12.6	13	86	4	44	
945	2.1	12.8	13	81	4	41	
1000	1.8	13	13	79	4	40	
1015	1.5	13.3	13	75	4	38	
1030	1.7	13.1	13	81	4	41	
1045	1.8	13.1	13	82	4	42	
1100	1.9	12.7	12	82	4	42	
1115	1.9	12.7	12	85	4	43	
1130	2.2	12.3	12	90	4	46	
1145	1.8	12.4	12	85	4	43	
1200	2.1	12.7	13	89	4	45	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-29-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	2.6	10.7	11	94	3	48	C
1230	2.3	10.9	11	90	3	46	
1245	2.2	11	12	88	4	45	
1300	2	10.9	11	86	3	44	
1315	2.3	10.5	11	91	3	46	
1330	2.3	10.7	10	89	3	45	
1345	2.2	10.7	277	85	83	43	
1400	3.6	10	167	102	54	52	
1415	3	10	11	96	3	49	
1430	2.6	10.2	10	93	3	47	
1445	2.5	10.2	10	90	3	46	
1500	2.4	10	10	89	3	45	
1515	2	10.5	10	83	3	42	
1530	2.1	10.5	10	86	3	44	
1545	2	10.1	11	85	3	43	
1600	1.9	10.3	11	85	3	43	
1615	2.6	10.3	10	94	3	48	
1630	4	9.9	9	110	3	56	C
1645	3.7	10.3	8	106	3	54	
1700	3.7	10.4	9	107	3	55	
1715	3.7	10.5	9	106	3	54	
1730	3.7	10.4	10	106	3	54	
1745	3.7	10.2	9	108	3	55	
1800	3.7	10.3	10	108	3	55	
1815	3.8	10.2	10	108	3	55	
1830	3.7	10.3	10	107	3	55	
1845	3.7	10.5	10	106	3	54	
1900	3.6	10.5	10	104	3	53	
1915	3.6	10.5	11	105	4	54	
1930	3.8	10.5	10	105	3	54	
1945	3.8	10.6	10	105	3	54	
2000	3.9	10.6	10	105	3	54	
2015	3.8	10.7	10	104	3	53	
2030	3.9	10.5	10	104	3	53	
2045	3.9	10.6	10	103	3	53	
2100	3.8	10.5	10	104	3	53	
2115	3.8	10.3	9	103	3	53	
2130	3.9	10.3	9	104	3	53	
2145	3.8	10.4	9	103	3	53	
2200	3.8	10.4	9	103	3	53	
2215	3.8	10.6	9	102	3	52	
2230	3.9	10.7	10	101	3	52	
2245	3.9	10.5	10	101	3	52	
2300	3.9	10.2	10	103	3	53	
2315	3.9	10.4	10	102	3	52	
2330	3.9	10.4	10	101	3	52	
2345	3.9	10.5	10	101	3	52	
2400	3.9	10.6	10	101	3	52	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-30-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	3.9	10.4	10	101	3	52	
30	3.8	10.6	10	98	3	50	
45	3.7	10.5	11	99	4	51	
100	3.9	10.5	11	100	4	51	
115	3.9	10.5	11	100	4	51	
130	4	10.6	11	100	4	51	
145	3.7	10.9	11	98	4	50	
200	4	10.5	11	101	4	52	
215	4	10.4	12	99	4	51	
230	3.7	10.6	12	94	4	48	
245	4.4	10.1	11	101	4	52	
300	4.2	10.3	12	99	4	51	
315	4.2	10.5	12	99	4	51	
330	4.2	10.6	12	98	4	50	
345	4.4	10.3	12	101	4	52	
400	3.8	10.5	12	96	4	49	
415	3.9	10.4	12	96	4	49	
430	3.9	10.5	12	97	4	49	
445	3.9	10.5	12	96	4	49	
500	3.8	10.5	12	96	4	49	
515	3.8	10.5	12	97	4	49	
530	3.9	10.4	12	96	4	49	
545	3.9	10.3	12	95	4	48	
600	3.9	10	12	97	4	49	
615	3.9	10.2	12	97	4	49	
630	3.9	10.3	12	97	4	49	
645	3.9	10.3	12	96	4	49	
700	4	10.2	12	97	4	49	
715	4	10.3	12	97	4	49	
730	3.9	10.1	12	97	4	49	
745	3.9	10.3	13	97	4	49	
800	3.8	10.4	12	98	4	50	
815	0	0	0	0	0	0	C
830	3.4	10.3	11	95	4	48	
845	2.2	11.2	10	79	3	40	
900	2.1	11.3	8	80	2	41	
915	1.9	11.2	8	78	2	40	
930	2	11	8	81	2	41	
945	2.3	10.8	8	85	2	43	
1000	2.3	10.7	8	85	2	43	
1015	2.3	10.8	8	84	2	43	
1030	2.3	10.8	8	86	2	44	
1045	2	10.7	8	81	2	41	
1100	2	10.9	8	82	2	42	
1115	2	10.8	8	83	2	42	
1130	2	11.2	8	85	2	43	
1145	2	10.6	8	86	2	44	
1200	2.1	10.4	8	85	2	43	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-30-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
1215	1.8	11.2	8	79	2	40	
1230	2.5	11.1	8	86	2	44	
1245	2.1	11.6	8	82	2	42	
1300	2.1	11.7	8	82	2	42	
1315	2	11.7	8	81	2	41	
1330	2	11.5	7	82	2	42	
1345	1.5	12.1	15	75	4	38	
1400	1.4	12.2	7	74	2	38	
1415	2.1	11.7	7	84	2	43	
1430	1.8	12	7	82	2	42	
1445	2.2	11.9	7	91	2	46	
1500	2.1	11.3	7	91	2	46	
1515	1.9	12.3	7	88	2	45	
1530	2	12.2	6	90	2	46	
1545	2.5	11.7	6	95	2	48	
1600	2.7	11.8	6	98	2	50	
1615	4.1	11.1	5	112	2	57	
1630	3.6	11.8	4	105	1	54	
1645	4	11.7	4	109	1	56	
1700	4.1	11.7	4	108	1	55	
1715	4.2	11.8	4	108	1	55	
1730	4.3	11.7	4	111	1	57	
1745	4.3	11.7	4	110	1	56	
1800	4.2	11.8	4	108	1	55	
1815	4.1	11.8	4	106	1	54	
1830	4.1	11.7	4	104	1	53	
1845	4.2	11.4	4	105	1	54	
1900	4.2	11.3	4	104	1	53	
1915	4.2	11	4	103	1	53	
1930	4.2	10.8	4	102	1	52	
1945	4.1	10.6	4	101	1	52	
2000	4.1	10.6	4	100	1	51	
2015	4.1	10.6	4	102	1	52	
2030	4.1	0	4	101	1	52	F
2045	4.2	0	4	103	1	53	F
2100	4.3	0	4	104	1	53	F
2115	4.2	0	5	103	2	53	F
2130	4.2	0	4	103	1	53	F
2145	4.2	0	4	103	1	53	F
2200	4.3	0	5	103	2	53	F
2215	4.3	0	5	104	2	53	F
2230	4.3	0	4	105	1	54	F
2245	4.4	0	4	104	1	53	F
2300	4.4	0	5	103	2	53	F
2315	4.3	0	5	102	2	52	F
2330	4.4	0	5	102	2	52	F
2345	4.4	0	5	103	2	53	F
2400	4.5	10	5	97	2	49	

NO on a mass basis is in terms of NO_2

SITE 2 STAGED AIR

DATE 3-31-1983 15 MIN DATA
LOAD 11500 BBL/D DRY STACK GAS

TIME	O2 VOL% MEAS	CO2 VOL% MEAS	CO PPMV MEAS	NO PPMV 3%O2	CO NG/J --	NO NG/J --	CODE
15	4.5	0	5	104	2	53	F
30	4.5	0	5	105	2	54	F
45	4.4	0	5	102	2	52	F
100	5.1	0	8	105	3	54	F
115	4.3	0	5	99	2	51	F
130	4.2	0	5	99	2	51	F
145	4.1	0	5	100	2	51	F
200	4.2	0	5	100	2	51	F
215	3.9	0	5	97	2	49	F
230	3.7	0	5	96	2	49	F
245	3.7	0	5	95	2	48	F
300	3.9	0	5	97	2	49	F
315	4	0	5	97	2	49	F
330	4.1	0	5	98	2	50	F
345	4	0	5	99	2	51	F
400	4.1	0	5	99	2	51	F
415	4.2	0	6	99	2	51	F
430	5.2	0	5	106	2	54	F
445	4.4	0	5	101	2	52	F
500	4.6	0	5	103	2	53	F
515	4.5	0	5	102	2	52	F
530	4.3	0	6	101	2	52	F
545	4.3	0	5	99	2	51	F
600	4.3	0	5	100	2	51	F
615	4.4	0	5	101	2	52	F
630	4.3	0	5	101	2	52	F
645	4.4	0	5	99	2	51	F
700	4.3	0	5	99	2	51	F/B
715	0	0	0	0	0	0	
730	0	0	0	0	0	0	
745	0	0	0	0	0	0	
800	0	0	0	0	0	0	
815	0	0	0	0	0	0	
830	0	0	0	0	0	0	
845	0	0	0	0	0	0	
900	0	0	0	0	0	0	
915	0	0	0	0	0	0	
930	0	0	0	0	0	0	
945	0	0	0	0	0	0	
1000	0	0	0	0	0	0	
1015	0	0	0	0	0	0	
1030	0	0	0	0	0	0	
1045	0	0	0	0	0	0	
1100	0	0	0	0	0	0	
1115	0	0	0	0	0	0	
1130	0	0	0	0	0	0	
1145	0	0	0	0	0	0	
1200	0	0	0	0	0	0	

NO on a mass basis is in terms of NO_2

DATA TABLE FOR FIGURE 5-8

STACK O_2 - 4%

DATE	TIME	NO (PPM, 3% O_2)
3/25	1900	101
	1930	101
	2000	100
	2030	101
	2045	102
	2100	100
	2115	99
	2130	98
	2145	97
3/26	2045	104
	2100	105
	2115	104
	2145	105
	2200	105
	2300	101
	2315	102
	2345	102
3/27	0045	101
	0100	101
	0145	101
	0200	102
	0215	102
	0230	100
	0245	100
	0300	100
	0400	101
	0415	99
	0430	99
	0445	99
	0500	100
	0515	102
	0530	102
	0600	101
	0615	100
	0830	98
3/30	0130	100
	0200	101
	0215	99
	0700	97
	0715	97
	1645	109

STACK O_2 - 2%

DATE	TIME	NO (PPM, 3% O_2)
3/28	0830	79
	1015	83
	1030	82
	1045	84
	1130	83
	1145	83
	1200	82
	1230	85
	1245	86
	1300	83
	1345	81
	1400	81
3/29	1300	86
	1515	83
	1545	85
3/30	0930	81
	1045	81
	1100	82
	1115	83
	1315	81
	1330	82
	1530	92

APPENDIX D

FUEL ANALYSES REPORTS

TYPICAL NO. 6 FUEL OIL ANALYSIS

	Mean	Standard Deviation
Carbon, %	88.28	0.27
Hydrogen, %	9.98	0.29
Ash, %	0.013	0.005
Nitrogen, %	0.78	0.12
Sulfur, %	0.87	0.06
Oxygen, % by Diff.	0.13	0.16
HHV (Btu/lb)	18035	80
API Gravity at 60°F	9.42	0.95

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY: Gas Lab

OPERATOR: J. Satcher

DATE: February 8, 1983

UNIT	Fuel Gas To 11H13					
SAMPLE DATE	2-8-83					
SAMPLE TIME	11⁰⁰ A.M.					
PERCENT	Gas Vol.					
HYDROGEN 13	14.6					
NITROGEN 9	2.1					
OXYGEN						
CARBON MONOXIDE 17	1.4					
CARBON DIOXIDE 21						
HYDROGEN SULFIDE 25						
METHANE 29	48.3					
ETHANE 33	15.2					
ETHYLENE 37	8.2					
PROPANE 41	2.9					
PROPYLENE 45	3.8					
ISOBUTANE 49	0.2					
NORMAL BUTANE 53	0.3					
TOTAL BUTENES 57	0.6					
1, 3-BUTADIENE 61						
ISOPENTANE 65	0.5					
NORMAL PENTANE 69	0.3					
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	1.5					
Specific Gravity	0.7397					
BTU / Cu. Ft	1234					

DIST: KVB

REMARKS:

PREPARED BY:

SUBMITTED BY:

LABORATORY Gas Lab
OPERATOR J. Satcher
DATE February 10, 1983

UNIT Gas Con	DeC$_3$ Btms.	DeC$_4$ Btms.	Reabs. Gas	Abs. Gas		
SAMPLE DATE	2-10-83	—	—			
SAMPLE TIME	8^{00} A.M.	—	—			
PERCENT	Liq. Vol.	—	Gas Vol.	Gas Vol.		
HYDROGEN 13			13.7	14.1		
NITROGEN 9			1.4	1.44		
OXYGEN						
CARBON MONOXIDE 17			1.0	1.03		
CARBON DIOXIDE 21			1.4	—		
HYDROGEN SULFIDE 25	0.2		1.4	—		
METHANE 29			42.8	44.0		
ETHANE 33	0.4		13.6	14.0		
ETHYLENE 37			7.1	7.3		
PROPANE 41	16.9		4.8	4.93		
PROPYLENE 45	16.0		6.9	7.1		
ISOBUTANE 49	15.9	0.7	1.0	1.03		
NORMAL BUTANE 53	13.4	3.1	0.8	.82		
TOTAL BUTENES 57	35.9	6.2	2.1	2.16		
1, 3-BUTADIENE 61	1.3	0.1	0.1	.11		
ISOPENTANE 65		5.7	0.4	.41		
NORMAL PENTANE 69		4.2	0.3	.31		
TOTAL PENTENES 73		14.3				
TOTAL C$_6$ PLUS 77	0.1	65.7	1.2	1.23		
Σ			100.0	99.17		
Btu/ft^3				1346		

DIST GDD(2) JAN
JAK LOW
PJK(3) P&I

REMARKS

PREPARED BY Joe Satcher

SUBMITTED BY

TOSCO CORPORATION
BAKERSFIELD REFINERY
GAS ANALYSIS REPORT

LABORATORY: Gas Lab
OPERATOR: J. Satcher
DATE: February 15, 1983

UNIT: Absorber Gas	Fuel Gas To 11H13					
SAMPLE DATE	2-15-83					
SAMPLE TIME	10^{00} A.M.					
PERCENT	Gas Vol.					
HYDROGEN 13	13.8					
NITROGEN 9	2.0					
OXYGEN	0.2					
CARBON MONOXIDE 17	1.3					
CARBON DIOXIDE 21						
HYDROGEN SULFIDE 25						
METHANE 29	44.8					
ETHANE 33	14.5					
ETHYLENE 37	8.0					
PROPANE 41	3.8					
PROPYLENE 45	6.0					
ISOBUTANE 49	0.4					
NORMAL BUTANE 53	0.5					
TOTAL BUTENES 57	1.6					
1, 3-BUTADIENE 61	0.1					
ISOPENTANE 65	0.5					
NORMAL PENTANE 69	0.3					
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	2.1					
Specific Gravity	0.8036					
BTU/Cu. Ft.	1330					

IT KVB

REMARKS

PREPARED BY Joe Satcher
SUBMITTED BY

81 08919 80)

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY: Gas Lab
OPERATOR: J. Satcher
DATE: February 17, 1983

UNIT Gas Con	DeC3 Btms	DeC4 Btms	Reabs. Gas	ABS GAS		
SAMPLE DATE	2-17-83	—	—			
SAMPLE TIME	8^00 A.M.	—	—			
PERCENT	Liq. Vol.	—	Gas Vol.	GAS VOL		
HYDROGEN 13			11.8	12.1		
NITROGEN 9			1.4	1.4		
OXYGEN						
CARBON MONOXIDE 17			1.2	1.2		
CARBON DIOXIDE 21			1.6	—		
HYDROGEN SULFIDE 25			1.2	—		
METHANE 29			39.9	41.1		
ETHANE 33	0.1		13.4	13.8		
ETHYLENE 37			7.3	7.5		
PROPANE 41	16.5		4.5	4.6		
PROPYLENE 45	14.8		7.2	7.4		
ISOBUTANE 49	20.8	0.6	1.1	1.1		
NORMAL BUTANE 53	6.2	3.6	1.3	1.3		
TOTAL BUTENES 57	39.6	8.9	2.5	2.6		
1, 3-BUTADIENE 61	1.8	0.2	0.1	.1		
ISOPENTANE 65		4.3	0.5	.5		
NORMAL PENTANE 69		3.2	0.4	.4		
TOTAL PENTENES 73		12.7				
TOTAL C_6 PLUS 77	0.2	66.6	4.5	4.6		
Σ 1			99.9	99.7		

GDC(2) JAV
JAK LOW
PJK(3) P&I

REMARKS

PREPARED BY: Jan Satcher
SUBMITTED BY

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY: GAS LAB

OPERATOR: J. SATCHER

DATE: FEBRUARY 22, 1983

UNIT GAS CON	REABS GAS	ABS GAS				
SAMPLE DATE	2-22-83	2-22-83				
SAMPLE TIME	1^{45} P.M.					
PERCENT	GAS VOL.	GAS VOL.				
HYDROGEN 13	2.9	2.9				
NITROGEN 9	1.1	1.1				
OXYGEN						
CARBON MONOXIDE 17	0.5	.5				
CARBON DIOXIDE 21	1.1	—				
HYDROGEN SULFIDE 25	0.2	—				
METHANE 29	29.3	29.7				
ETHANE 33	11.7	11.9				
ETHYLENE 37	6.6	6.7				
PROPANE 41	17.1	17.3				
PROPYLENE 45	5.8	5.9				
ISOBUTANE 49	16.6	16.8				
NORMAL BUTANE 53	3.6	3.6				
TOTAL BUTENES 57	1.7	1.7				
1, 3-BUTADIENE 61	0.1	.1				
ISOPENTANE 65	0.3	.3				
NORMAL PENTANE 69	0.2	.2				
TOTAL PENTENES 73	0.3	.3				
TOTAL C_6 PLUS 77	0.9	.9				
1	100.0	99.9	-			

DIST: GOD(2) JAK PJC(2) JAU LOW

REMARKS:

PREPARED BY:

SUBMITTED BY:

81 089 (9/69)

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY: GAS LAB

OPERATOR: D. SPRAGUE

DATE: FEBRUARY 25, 1983

UNIT: FUEL GAS	NO. 1 FUEL GAS DRUM					
SAMPLE DATE	2-24-83					
SAMPLE TIME	4^{30} PM					
PERCENT	GAS VOL					
HYDROGEN 13	7.0					
NITROGEN 9	2.4					
OXYGEN	0.3					
CARBON MONOXIDE 17	0.9					
CARBON DIOXIDE 21	1.8					
HYDROGEN SULFIDE 25						
METHANE 29	56.4					
ETHANE 33	11.5					
HYLENE 37	4.9					
PROPANE 41	10.2					
PROPYLENE 45	0.9					
ISOBUTANE 49	0.4					
NORMAL BUTANE 53	0.6					
TOTAL BUTENES 57	0.4					
1, 3-BUTADIENE 61						
ISOPENTANE 65	0.4					
NORMAL PENTANE 69	0.2					
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	1.5					
BTU/ CU. FT.	1294.76					
SPECIFIC GRAVITY	0.8082					

GDD

REMARKS:

PREPARED BY: D Sprague

SUBMITTED BY:

TOSCO CORPORATION
BAKERSFIELD REFINERY
GAS ANALYSIS REPORT

LABORATORY: Gas Lab

OPERATOR: J. Satcher

DATE: March 1, 1983

IIT: Crude Unit	Crude Vapors From 11D16	Condensate From 11D12	Comp. Disch. Vapors 11D17	Comp. Disch Cond. 11D17	No. 1 Fuel Gas Drum	
SAMPLE DATE	3-1-83	–	–	–	–	
SAMPLE TIME	$10^{\underline{00}}$ A.M.	–	–	–	–	
PERCENT	Gas Vol.	Liq. Vol.	Gas Vol.	Liq. Vol.	Gas Vol.	
HYDROGEN 13			0.6		5.8	
NITROGEN 9	4.3		15.5		2.6	
OXYGEN	0.4		0.1			
CARBON MONOXIDE 17			0.3		1.6	
CARBON DIOXIDE 21	8.0		5.7		2.5	
HYDROGEN SULFIDE 25						
METHANE 29	34.6	0.1	48.0	0.5	54.0	
ETHANE 33	14.6	0.2	9.4	2.8	14.6	
ETHYLENE 37	0.1		2.4		7.8	
PROPANE 41	6.3	3.1	8.5	9.8	1.8	
PROPYLENE 45	0.1		0.6	2.3	2.3	
ISOBUTANE 49	2.6	3.1	1.8	4.8	0.2	
NORMAL BUTANE 53	8.9	12.6	4.5	20.2	0.6	
TOTAL BUTENES 57	0.7	0.9	0.5	5.7	1.8	
1, 3-BUTADIENE 61				0.4	0.1	
ISOPENTANE 65	4.1	11.3	0.8	9.5	0.2	
NORMAL PENTANE 69	4.4	13.6	0.6	8.2	0.3	
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	10.9	55.0	0.4	35.7	3.9	
Specific Gravity	1.9115	0.6553	0.9543	0.6158	0.8584	

DIST 600(2)

REMARKS KVB

PREPARED BY: Jan Satcher

SUBMITTED BY:

61 089 (9 80)

TOSCO CORPORATION
BAKERSFIELD REFINERY
GAS ANALYSIS REPORT

LABORATORY: Gas Lab		OPERATOR: J. Satcher			DATE: March 3, 1983	
UNIT	No. 1 Fuel Gas Drum					
SAMPLE DATE	3-3-83					
SAMPLE TIME	4³⁰ P.M.					
PERCENT	Gas Vol.					
HYDROGEN 13	6.4					
NITROGEN 9	1.9					
OXYGEN						
CARBON MONOXIDE 17	1.3					
CARBON DIOXIDE 21	2.5					
HYDROGEN SULFIDE 25	0.2					
METHANE 29	42.5					
ETHANE 33	13.0					
THYLENE 37	6.7					
PROPANE 41	12.3					
PROPYLENE 45	4.5					
ISOBUTANE 49	0.5					
NORMAL BUTANE 53	1.1					
TOTAL BUTENES 57	2.9					
1, 3-BUTADIENE 61	0.3					
ISOPENTANE 65	0.3					
NORMAL PENTANE 69	0.5					
TOTAL PENTENES 73	0.7					
TOTAL C_6 PLUS 77	2.5					
BTU / Cu. Ft	1531					

T KVB

REMARKS

PREPARED BY: Joe Satcher

SUBMITTED BY:

C89 (9-80)

TOSCO CORPORATION
BAKERSFIELD REFINERY
GAS ANALYSIS REPORT

LABORATORY Gas Lab
OPERATOR J. Satcher
DATE March 16, 1983

UNIT Fuel Gas	No. 1 Fuel Gas Drum					
SAMPLE DATE	3-16-83					
SAMPLE TIME	$4^{\underline{00}}$ P.M.					
PERCENT	Gas Vol.					
HYDROGEN 13	6.4					
NITROGEN 9	2.3					
OXYGEN						
CARBON MONOXIDE 17	1.5					
CARBON DIOXIDE 21	2.6					
HYDROGEN SULFIDE 25						
METHANE 29	44.8					
ETHANE 33	13.3					
HYLENE 37	7.2					
PROPANE 41	3.8					
PROPYLENE 45	4.5					
ISOBUTANE 49	1.0					
NORMAL BUTANE 53	1.8					
TOTAL BUTENES 57	3.0					
1, 3-BUTADIENE 61	0.3					
ISOPENTANE 65	0.3					
NORMAL PENTANE 69	0.3					
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	2.0					
BTU / Cu. Ft	1381					

KVB	REMARKS	PREPARED BY SUBMITTED BY

81 089 (9 80)

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY GAS LAB		OPERATOR J. SATCHER			DATE MARCH 17, 1983	
.IT FUEL GAS	SO. CAL NAT GAS	No. 1 FUEL GAS DRUM				
SAMPLE DATE	3-17-83	3-21-83				
SAMPLE TIME	1^{00} P.M.	3^{00} P.M.				
PERCENT	GAS VOL.	~				
HYDROGEN 13		6.0				
NITROGEN 9	0.8	2.4				
OXYGEN						
CARBON MONOXIDE 17		1.4				
CARBON DIOXIDE 21	1.0	2.4				
HYDROGEN SULFIDE 25		0.2				
METHANE 29	90.7	48.5				
ETHANE 33	6.1	12.5				
HYLENE 37		6.6				
PROPANE 41	0.8	4.3				
PROPYLENE 45		4.8				
ISOBUTANE 49	0.1	1.0				
NORMAL BUTANE 53	0.1	2.0				
TOTAL BUTENES 57		3.3				
1, 3-BUTADIENE 61		0.3				
ISOPENTANE 65		0.5				
NORMAL PENTANE 69		0.5				
TOTAL PENTENES 73		0.5				
TOTAL C_6 PLUS 77	0.2	2.5				
BTU/CU. FT	1065	1446				
SP. GR		0.9312				

T KVB	REMARKS	PREPARED BY SUBMITTED BY Jim Satcher

81 089 (2 80)

TOSCO CORPORATION
BAKERSFIELD REFINERY
GAS ANALYSIS REPORT

LABORATORY Gas Lab
OPERATOR J. Satcher
DATE March 24, 1983

#T Fuel Gas	No. 1 Fuel Gas Drum					
SAMPLE DATE	3-24-83					
SAMPLE TIME	4^{30} P.M.					
PERCENT	Gas Vol.					
HYDROGEN 13	12.6					
NITROGEN 9	1.7					
OXYGEN						
CARBON MONOXIDE 17	1.0					
CARBON DIOXIDE 21	1.5					
HYDROGEN SULFIDE 25	0.5					
METHANE 29	45.4					
ETHANE 33	14.7					
IYLENE 37	5.7					
PROPANE 41	5.4					
PROPYLENE 45	3.1					
ISOBUTANE 49	1.3					
NORMAL BUTANE 53	2.1					
TOTAL BUTENES 57	2.2					
1, 3-BUTADIENE 61						
ISOPENTANE 65	0.6					
NORMAL PENTANE 69	0.3					
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	1.9					
BTU / Cu. Ft	1363					

KVB

REMARKS

PREPARED BY

SUBMITTED BY

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY: GAS LAB
OPERATOR: J. SATCHER
DATE: MARCH 30, 1983

UNIT	ABS. GAS TO 11H13					
SAMPLE DATE	3-30-83					
SAMPLE TIME	8^{00} A.M.					
PERCENT	GAS VOL.					
HYDROGEN 13	16.8					
NITROGEN 9	1.5					
OXYGEN						
CARBON MONOXIDE 17	0.9					
CARBON DIOXIDE 21						
HYDROGEN SULFIDE 25						
METHANE 29	42.3					
ETHANE 33	16.6					
YLENE 37	7.9					
PROPANE 41	5.0					
PROPYLENE 45	5.8					
ISOBUTANE 49	0.5					
NORMAL BUTANE 53	0.6					
TOTAL BUTENES 57	1.0					
1, 3-BUTADIENE 61						
ISOPENTANE 65	0.3					
NORMAL PENTANE 69	0.2					
TOTAL PENTENES 73	0.2					
TOTAL C_6 PLUS 77	0.4					
BTU / CU. FT	1280					

KVB

REMARKS

PREPARED BY

SUBMITTED BY

11 H13 4/5/85

```
HYDROGEN          13.778     1.35   461293 08       6.406
  2                0.        1.71     2462 05
CO2                0.308     2.58    37311 02       1.771
-THYLENE           7.439     3.2    893447 02       1.786
_THANE            16.803     3.8   2017472 03       1.786
  6                0.        6.32      144 01
OXYGEN             0.022     8.06     2080 01       2.261
NITROGEN           0.977     8.36   103561 01       2.024
METHANE           47.769     9.08  3898455 02       2.628
CO                 0.961     9.6    101850 03       2.024
C6 PLUS  1         0.515    17.23   147268 01       0.75
 12                0.       17.9   1573862 08
 13                0.       18.    1738603 25
 14                0.       19.41    17234 01
PROPANE            4.738    20.71   855337 01       1.188
PROPLYENE          4.992    21.76   792202 01       1.351
I-C4               0.311    23.87    66346 01       1.005
n-C4               0.351    25.68    75330 01       1.
BUTENE   2         0.143    28.11    29052 02       1.053
i-C4-2   2         0.269    28.87    56045 03       1.031
T-C4-2   2         0.15     30.14    32123 01       1.
C-C4-2   2         0.107    31.65    23469 01       0.98
BUTADIENE          0.01     32.79     1890 01       1.064
i-C5               0.212    34.2     55251 01       0.826
n-C5               0.145    37.62    38134 21       0.813

TOTALS           100.              13020221


 UMMARY REPORT

NAME             MOLE %      B.T.U.        SP.GR.          VP

HYDROGEN           13.8      44.6407       0.0096          0.
CO2                 0.3      0.            0.0047          0.
ETHYLENE            7.4     119.0017       0.0721          0.
ETHANE             16.8     297.2115       0.1744          0.
ACETYLENE           0.       0.            0.              0.
OXYGEN              0.       0.            0.0002          0.
NITROGEN            1.       0.            0.0094          0.
METHANE            47.8     482.3236       0.2646          0.
CO                  1.        3.0848       0.0093          0.
C6 PLUS  1          0.5      23.0447       0.0164          0.
PROPANE             4.7     119.2791       0.0721          0.
PROPLYENE           5.      116.4983       0.0725          0.
H2S                 0.       0.            0.              0.
I-C4                0.3      10.1159       0.0062          0.
n-C4                0.4      11.45         0.007           0.
BUTENE   2          0.7      20.6099       0.013           0.
BUTADIENE           0.        0.2881       0.0002          0.
i-C5                0.2       8.48         0.0053          0.
n-C5                0.1       5.8145       0.0036          0.

TOTALS:           100.      1261.84        0.7407          0.


B.T.U./CU.FT.:              1261.84
LPG VAPOR PRESSURE:            0.
```

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

'ABORATORY: Gas Lab		OPERATOR: J. Satcher			DATE: June 10, 1983	
UNIT: Gas Con	DeC$_3$ Btms.	Reabs. Gas	Abs. Gas			
SAMPLE DATE	6-10-83	—	—			
SAMPLE TIME	7^{00} A.M.	—	—			
PERCENT	Liq. Vol.	Gas Vol.	Gas Vol.			
HYDROGEN 13		15.0	15.37			
NITROGEN 9		1.7	1.74			
OXYGEN						
CARBON MONOXIDE 17		1.0	1.02			
CARBON DIOXIDE 21		1.6	—			
HYDROGEN SULFIDE 25		0.8	—			
METHANE 29		41.7	42.73			
ETHANE 33		15.4	15.78			
ETHYLENE 37		8.5	8.71			
PROPANE 41	12.1	4.2	4.30			
PROPYLENE 45	9.7	7.2	7.38			
ISOBUTANE 49	12.7	0.4	.41			
NORMAL BUTANE 53	16.3	0.3	.31			
TOTAL BUTENES 57	42.3	1.1	1.13			
1, 3-BUTADIENE 61	1.7					
ISOPENTANE 65	2.1	0.2	.21			
NORMAL PENTANE 69	1.2	0.1	.11			
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	1.9	0.8	1.95			
BTU/Cu Ft.		1265				

ST: GDD JAK JPM(2) JAV LOW(2) P&I A-CONT	REMARKS:	PREPARED BY: Jan Satcher SUBMITTED BY:

81 089 (9-80)

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY Gas Lab		OPERATOR				DATE October 7, 1982	
UNIT		ABS. GAS TO 11H13					
SAMPLE DATE		10-7-82					
SAMPLE TIME		$10^{\underline{00}}$ A.M.					
PERCENT		Gas Vol.					
HYDROGEN	13	13.5					
NITROGEN	9	1.2					
OXYGEN							
CARBON MONOXIDE	17	1.4					
CARBON DIOXIDE	21						
HYDROGEN SULFIDE	25						
METHANE	29	47.0					
ETHANE	33	18.0					
ETHYLENE	37	8.7					
PROPANE	41	2.8					
PROPYLENE	45	4.5					
ISOBUTANE	49	0.7					
NORMAL BUTANE	53	0.5					
TOTAL BUTENES	57	0.8					
1, 3-BUTADIENE	61						
ISOPENTANE	65	0.2					
NORMAL PENTANE	69	0.1					
TOTAL PENTENES	73						
TOTAL C_6 PLUS	77	0.6					

DIST	REMARKS	PREPARED BY
		SUBMITTED BY

TOSCO CORPORATION
BAKERSFIELD REFINERY
GAS ANALYSIS REPORT

LABORATORY Gas Lab		OPERATOR J. Satcher			DATE October 15, 1982	
UNIT Fuel Gas	No. 1 Fuel Gas Drum	Abs. Gas to 11H13				
SAMPLE DATE	10-15-82	—				
SAMPLE TIME	2⁰⁰ P.M.	—				
PERCENT	Gas Vol.	—				
HYDROGEN 13	12.8	13.0				
NITROGEN 9	2.1	1.5				
OXYGEN	0.2	0.1				
CARBON MONOXIDE 17	0.8	1.0				
CARBON DIOXIDE 21	1.7					
HYDROGEN SULFIDE 25	0.1					
METHANE 29	55.3	44.4				
ETHANE 33	16.4	17.3				
ETHYLENE 37	6.5	7.5				
PROPANE 41	1.0	4.7				
PROPYLENE 45	0.9	5.8				
ISOBUTANE 49	0.2	0.6				
NORMAL BUTANE 53	0.4	0.6				
TOTAL BUTENES 57	0.3	1.2				
1, 3-BUTADIENE 61						
ISOPENTANE 65	0.2	0.4				
NORMAL PENTANE 69	0.2	0.2				
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	0.8	1.6				

DIST KVB	REMARKS	PREPARED BY Jan Satch SUBMITTED BY

TOSCO CORPORATION
BAKERSFIELD REFINERY
GAS ANALYSIS REPORT

LABORATORY Gas Lab

OPERATOR J. Satcher

DATE October 21, 1982

UNIT Fuel Gas	ABS. GAS TO 11H13					
SAMPLE DATE	10-20-82					
SAMPLE TIME	4³⁰ P.M.					
PERCENT	Gas Vol.					
HYDROGEN 13	13.7					
NITROGEN 9	1.7					
OXYGEN	0.1					
CARBON MONOXIDE 17	1.2					
CARBON DIOXIDE 21						
HYDROGEN SULFIDE 25						
METHANE 29	45.3					
ETHANE 33	17.7					
ETHYLENE 37	7.8					
PROPANE 41	4.2					
PROPYLENE 45	5.7					
ISOBUTANE 49	0.2					
NORMAL BUTANE 53	0.3					
TOTAL BUTENES 57	0.6					
1, 3-BUTADIENE 61						
ISOPENTANE 65	0.3					
NORMAL PENTANE 69	0.2					
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	0.8					

DIST KVB

REMARKS

PREPARED BY

SUBMITTED BY

81 C89 9 80

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY Gas Lab		OPERATOR J. Satcher			DATE October 21, 1982	
UNIT Gas Con.	DeC$_3$ Btms.	DeC$_4$ Btms.	Reabs. Gas			
SAMPLE DATE	10-21-82	—	—			
SAMPLE TIME	8^{00} A.M.	—	—			
PERCENT	Liq. Vol.	—	Gas Vol.			
HYDROGEN 13			13.1			
NITROGEN 9			1.7			
OXYGEN			0.1			
CARBON MONOXIDE 17			1.3			
CARBON DIOXIDE 21			1.8			
HYDROGEN SULFIDE 25						
METHANE 29			46.6			
ETHANE 33			17.6			
ETHYLENE 37			8.0			
PROPANE 41	13.7		3.5			
PROPYLENE 45	9.5		4.7			
ISOBUTANE 49	15.5		0.2			
NORMAL BUTANE 53	18.9		0.1			
TOTAL BUTENES 57	40.4		0.3			
1, 3-BUTADIENE 61	1.2					
ISOPENTANE 65	0.2		0.2			
NORMAL PENTANE 69	0.3		0.1			
TOTAL PENTENES 73						
TOTAL C$_6$ PLUS 77	0.3		0.6			

DIST GDD (2) JAV JAK LOW PJK (3) 7 & I	REMARKS	PREPARED BY SUBMITTED BY

81 189 9 80

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY Gas Lab
OPERATOR J. Satcher
DATE October 25, 1982

UNIT Absorber	ABS. GAS TO 11H13					
SAMPLE DATE	10-25-82					
SAMPLE TIME	4^{00} P.M.					
PERCENT	Gas Vol.					
HYDROGEN 13	12.0					
NITROGEN 9	1.5					
OXYGEN						
CARBON MONOXIDE 17	1.3					
CARBON DIOXIDE 21	0.1					
HYDROGEN SULFIDE 25						
METHANE 29	44.9					
ETHANE 33	17.3					
ETHYLENE 37	8.0					
PROPANE 41	4.9					
PROPYLENE 45	7.2					
ISOBUTANE 49	0.3					
NORMAL BUTANE 53	0.3					
TOTAL BUTENES 57	0.7					
1, 3-BUTADIENE 61						
ISOPENTANE 65	0.3					
NORMAL PENTANE 69	0.2					
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	0.8					

DIST KVB

REMARKS

PREPARED BY Joe Satcher

SUBMITTED BY

81 089 (9 80)

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY Gas Lab		OPERATOR J. Satcher			DATE October 26, 1982	
UNIT Fuel Gas	No. 1 Fuel Gas Drum					
SAMPLE DATE	10-26-82					
SAMPLE TIME	4^{15} P.M.					
PERCENT	Gas Vol.					
HYDROGEN 13	11.6					
NITROGEN 9	2.2					
OXYGEN	0.2					
CARBON MONOXIDE 17	1.2					
CARBON DIOXIDE 21	2.0					
HYDROGEN SULFIDE 25						
METHANE 29	55.3					
ETHANE 33	16.9					
ETHYLENE 37	7.3					
PROPANE 41	1.0					
PROPYLENE 45	1.2					
ISOBUTANE 49	0.1					
NORMAL BUTANE 53	0.2					
TOTAL BUTENES 57	0.2					
1, 3-BUTADIENE 61						
ISOPENTANE 65	0.1					
NORMAL PENTANE 69	0.1					
TOTAL PENTENES 73						
TOTAL C_6 PLUS 77	0.3					

DIST KVB	REMARKS	PREPARED BY SUBMITTED BY

81 089 (9-80)

TOSCO CORPORATION
BAKERSFIELD REFINERY

GAS ANALYSIS REPORT

LABORATORY: Gas Lab
OPERATOR: J. Satcher
DATE: October 27, 1982

UNIT Fuel Gas	ABS GAS TO 11H13	NO. 1 FUEL GAS DRUM.					
SAMPLE DATE	10-27-82	—					
SAMPLE TIME	4^{00} P.M.	—					
PERCENT	Gas Vol.	—					
HYDROGEN 13	14.1	13.3					
NITROGEN 9	1.4	1.5					
OXYGEN							
CARBON MONOXIDE 17	1.2	0.9					
CARBON DIOXIDE 21		1.7					
HYDROGEN SULFIDE 25							
METHANE 29	45.6	50.8					
ETHANE 33	18.1	15.9					
ETHYLENE 37	8.0	6.5					
PROPANE 41	3.7	3.1					
PROPYLENE 45	5.4	2.9					
ISOBUTANE 49	0.3	0.7					
NORMAL BUTANE 53	0.3	0.8					
TOTAL BUTENES 57	0.8	0.8					
1, 3-BUTADIENE 61							
ISOPENTANE 65	0.3	0.3					
NORMAL PENTANE 69	0.2	0.2					
TOTAL PENTENES 73							
TOTAL C_6 PLUS 77	0.7	0.6					

DIST. KVB

REMARKS

PREPARED BY

SUBMITTED BY

81 089 (9-80)

APPENDIX E

QUALITY ASSURANCE INTERNAL AUDIT

METHOD CHECKLIST TO BE USED BY AUDITORS 2/24/83

yes	no	comment	OPERATION
			Presampling Preparations
✓		Excellant	1. Knowledge of process conditions
✓		vs. EPA protocol 1	2. Traceability of calibration gas established
✓			3. Calibration of pertinent equipment,
			On-Site Measurements
✓			4. Leak test of sampling train
✓			5. NDIR warmup per manufacturer's recommendations
✓			6. Purging the train prior to sampling
	✓	NOT Needed	7. Proportional sampling
✓			8. Frequency of zero and span checks
✓			9. Drying agents checked and replaced frequently
			Postsampling
		N.A.	10. Transfer and handling of sample
✓			11. Data reduction procedure/check
✓			12. Calibration checks

GENERAL COMMENTS:

KVB

Engineer FROHOFF/GRIFFIN OBSV

MONITOR PERFORMANCE TEST DATA SHEET

RESPONSE TIME FOR CONTINUOUS INSTRUMENTS

Date of Test 2/24/83 (10:30)
Analyzer type TECO 10A S/N EPA 059310
Span Gas Concentration 440.6 ppm NO (AA6758 Protocol *1)

Analyzer Span Setting 6.49 ppm

Upscale
(Sample to stability)
1 75 seconds
2 78 seconds
3 73 seconds
Average upscale response 75.3 seconds

instrument response
(sample to span) - 90% response
63.17 sec
65.21 sec
67.19 sec
65.19 sec average

Downscale
(Sample to zero)
1 70 seconds
2 80 seconds
3 80 seconds
Average downscale response 76.7 seconds.

instrument response
(span to sample) - 90% response
61.18 sec
64.99 sec
71.01 sec
65.73 sec average

System average response time (slower time) = 75.3 seconds.

% deviation from slower system average response $= \left[\frac{\text{average upscale minus average downscale}}{\text{slower time}}\right] \times 100\% =$ 1.86.

Method 20
1) Zero to Stability
2) Sample to Stability
3) Span to Stability
4) Sample to Stability
- Repeat -

Stability
30 sec = < 1% span Δ
2 min = < 5% span Δ

Data Sheet 6017-35
40CFR60/App. B
7/1/77

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CALIBRATION GAS ANALYSIS DATA SHEET

Western Engineering Division
Technical Services

Date 2/24/83 Operator FROHOFF / GRIFFIN OBSV.

Reference

Instrument ID/SN EPA#059310 Model 10A

Manufacturer TECO

Zero Gas Composition N_2 Manufacturer SCOTT

Bottle ID AAL 6758

Certified Span Gas

Composition NO, N_2, BAL, N_2 Concentration 440.6 NO / 442.7 NO_x

Manufacturer SCOTT

Bottle ID AAL 2216 Accuracy ± 1% %

Certification: ☐ NBS/SRM ☒ EPA Protocol 1

☐ EPA Reference Method ________

Trial Gas

Bottle ID AAL 6666 Composition NO, NO_2, CO_2, N_2 Mfgr SCOTT

Labeled Concentration 68.2 NO / 68.6 NO_x 12.13 CO_2 Rated Accuracy ± 1%

Instrument Range 0 – 1000 ppm

Calibration Data

Run No.	Indicated Concentration*	Difference
1	64 ppm NO	4 ppm
2	64 PPM NO	4 PPM
3	65 PPM NO	3 PPM
Average	64.3 PPM	

---

*Zero and span checks between runs.

KVB®

CALIBRATION GAS ANALYSIS DATA SHEET

Western Engineering Division
Technical Services

Date 2/24/83 Operator FROMOFF/GRIFFIN OBSV.

Reference

Instrument ID/SN EPA# 059310 Model 10 A

Manufacturer TECO

Zero Gas Composition N_2 Manufacturer SCOTT

Bottle ID AAL 6758

Certified Span Gas

Composition NO, NO_2, BAL N_2 Concentration 440.6 NO / 442.7 NOX

Manufacturer SCOTT

Bottle ID AAL 2216 Accuracy ± 1 % %

Certification: ☐ NBS/SRM ☒ EPA Protocol 1

☐ EPA Reference Method ________

Trial Gas

Bottle ID A-2063 Composition NO, NO_2, CO_2, N_2 Mfgr SCOTT

Labeled Concentration 602.0 NO/605.9 NO_x 29.96 CO_2 Rated Accuracy ± % GRAVIMETRIC

Instrument Range 0-1000 ppm

Calibration Data

Run No.	Indicated Concentration*	Difference
1	560 ppm NO	42 ppm
2	557 ppm NO	45 ppm
3	557 ppm NO	45 ppm
Average	558	

NOTE - VERY HI CO_2 BACKGROUND 18 MO. OLD GAS

---

*Zero and span checks between runs.

KVB®

CALIBRATION GAS ANALYSIS DATA SHEET

Western Engineering Division
Technical Services

Date 2/23/83 Operator Jim MARKEE/FROHOFF OBSV

Reference

Instrument ID/SN EPA # 059310 Model 10A

Manufacturer Teco – Thermo Electron

Zero Gas Composition Nitrogen Manufacturer Scott Specialty Gas

Bottle ID AAL-9414

Certified Span Gas

Composition NO, NO_2, BAL N_2 Concentration 440.6 NO/442.7 NOX

Manufacturer Scott Specialty Gas

Bottle ID AAL 2216 Accuracy ± 1 % %

Certification: ☐ NBS/SRM ☒ EPA Protocol 1

☐ EPA Reference Method 20

Trial Gas

Bottle ID AAL 1765 Composition ________ Mfgr Scott Specialty Gas

Labeled Concentration 201 NOX 200.8 NO Co^2 12.27 Rated Accuracy ± 1%

Instrument Range 0 - 4000

Balance Gas Nitrogen

Calibration Data

Run No.	Indicated Concentration*	Difference
1	195 ppm NO	6 PPM
2	194 ppm NO	7 PPM
3	194 ppm NO	7 ppm
Average	194.3 ppm NO	6.7

---

*Zero and span checks between runs.

KVB

TECHNICAL MEMORANDUM

TO:	S. Cherry	DATE:	Sept. 7, 1983
FROM:	[redacted]	NO.:	TM71-R-1126R

SUBJECT: QUALITY ASSURANCE ACTIVITIES, AUGUST 1983

COPIES: W. Carter, S. Hunter, S. Kerho, L. Smith

The first internal lab procedure and calculation checks have been performed for EPA Method 6. Preparation of the pseudo test sample (standardized H_2SO_4 in weak peroxide absorbing solutions) and data sheets were performed by the Q.A. Officer, Roger Griffin. Lab analyses and calculations were performed by Jim Markee, one of the field test technicians. The results were as follows:

	SOx Audit No. A	B	C	D	Average
SDCF Sampled:					
QA Reference	9.674	10.116	9.566	9.483	
Lab Calc	9.68	10.12	9.55	9.48	
% Error	+0.06	+0.04	-0.17	-0.03	-0.0025
ppmV - SO_2					
QA Reference	198.8	414	200.6	438	
Lab Calc	201	418	208	439	
% Error	+1.1	+0.97	+3.7	+0.2	+1.5

These results compare very favorably with EPA's QA Handbook in which gas volume calculation (SDCF) errors of less than 0.1% are considered to be the same values. The computed pseudo-SO_2 concentration errors average +1.5% which is significantly better than the 6% error reported in the QA Handbook (Section 3.5).

Roger D. Griffin

RDG:gc

KVB

IO#10

INTEROFFICE MEMORANDUM

TO: R. Griffin

DATE: April 7, 1983

FROM: R. Benson

NO.: IO72-806032-4180

SUBJECT SO_x TEST AUDIT FOR EPA QUALITY ASSURANCE PROGRAM

Attached are the SO_x audit sheets compiled and completed by Jim Markee. The titrations and calculations were performed as per your request.

Ron Benson

RC:sm

SO₂

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SOx TEST DATA SHEET

Test No. SOX AUDIT A   Date 4/4/83   Plant/Unit No. FIRE & BRIMSTONE POWER   Unit Load (MW) ______

Sample Location STACK 1   Control Box EW 914   Tests Conducted By ______

TEST DATA: $Y_D = 1.015$

Time	Meter Vol. ft³	Orifice ΔH " H₂O	Vacuum " Hg	Stack Temp. °F	Probe Temp. °F	Coil ~~Oven~~ Temp. °F	Impinger Temp., °F In	Impinger Temp., °F Out	Meter Temp., °F In	Meter Temp., °F Out	Excess O₂ %
START	032.675 (V_I)	1.0	4	325	325	149	100	62	71	81	4
20 mins	033.72	1.0	4			148	101	61	73	88	
	035.69	1.1	4	324	340	150	101	61	78	89	4
	037.62	1.0	4			150		-	79	91	4
	039.69	1.0	4	328	340	149	102	68	80	91	4
STOP	042.620 (V_F)	1.0	4	329					81	91	4
AVG.	9.945	1.0	4	326	335	149	101	63	77	88.5	4

Barometric Pres. 29.87 "Hg   Boiler using additive (Type/Rate) ______

****

METER VOLUME:

$V_F - V_I = V_m =$ 42.620 − 32.675 = 9.95 ft³;   Sampling Rate = $\frac{V_m}{\text{Length of Test}}$ = .50 ft³/min.

Temp. & Pres. Correction: $V_S = \frac{B.P. + \frac{\Delta H}{13.6}}{29.92} \times V_m \times \frac{520°R}{T_m \text{ Avg. } °R} = \frac{29.87 + \frac{1.0}{13.6}}{29.92} \times 9.95 \times \frac{520}{\underset{(83+460)}{543}} = 9.54$ SCF

Meter Correction: $V_{sc} = V_S \times$ Meter Correction Factor (YD) = 9.54 × 1.015 = 9.68 SCF

****

FLUE GAS MOISTURE:

Imp #1 (gm) ______ − ______ = ______ gm   Imp #3 (gm) ______ − ______ = ______ gm

Imp #2 (gm) ______ − ______ = ______ gm   Imp #4 (gm) (Silica gel) ______ − ______ = ______ gm

Σgm water = 29 gm

29 gm $H_2O \times 0.0464 \frac{ft^3}{gm}$ = 1.35 ft³ H_2O (H_2O Vol.)

(V_{sc}) + H_2O Vol. = 9.68 + 1.35 = 11.03 ft³ Total Sample Volume; $\frac{H_2O \text{ Vol.} \times 100\%}{\text{Total Sample Vol.}}$ = 12.24 % H_2O

****

TITRATIONS:

Normality of Barium perchlorate ~~NaOH~~ solution = .01029 N

Sample Titrated By J. M.

Date Samples Titrated 4/6/83

Date ~~NaOH~~ Standarized 3/7/83

Probe inlet Plug* & Probe sample − ______ ml

Coil inlet Plug* sample − ______ ml

Coil and Frit sample − ______ ml

Impingers (Sample vol. 285 ml; Aliquot 10 ml) − (1) 15.9 ml, (2) 15.8 ml, (3) 16.1 ml, 15.9 (Avg.)

* If SOx test is conducted on a boiler where a fuel additive is being injected, these plugs shall be kept separate and water extracts taken for chemical analysis of magnesium and sulfate.

****

SO2

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SOx TEST DATA SHEET

SOx Audit

Test No. B Date 4/4/83 Plant/Unit No. Fire + Brimstone Power Unit Load (MW) ______

Sample Location Stack 2 Control Box EN 914 Tests Conducted By RDJ

$Y_D = 1.015$

TEST DATA:

20 mins

Time	Meter Vol. ft³	Orifice ΔH " H_2O	Vacuum " H_g	Stack Temp. °F	Probe Temp. °F	~~Oven~~ COIL Temp. °F	Impinger Temp., °F In	Impinger Temp., °F Out	Meter Temp., °F In	Meter Temp., °F Out	Excess O_2 %
START	058.82 (V_I)	2.0	5	480	475	149	100	65	75	78	2.9
	060.74	2.0	5	485	480	151	105	70	79	82	2.8
	062.69	2.0	5.2	483	480	150	106	72	82	85	2.9
	064.59	2.1	5.5	485	480	150	106	72	88	89	2.9
	066.70	2.1	5.5	485	485	149	106	75	91	93	2.8
STOP	069.25 (V_F)	2.1	5.5	480	482	150	106	74	95	97	2.9
AVG.	10.43	2.0	5.3	483	480	150	105	71	85	87	2.9

Barometric Pres. 29.87 "Hg Boiler using additive (Type/Rate) ______

****

METER VOLUME:

$V_F - V_I = V_m = 69.25 - 58.82 = 10.43$ ft³; Sampling Rate $= \frac{V_m}{\text{Length of Test}} = .52$ ft³/min.

Temp. & Pres. Correction: $V_S = \frac{\text{B.P.} + \frac{\Delta H}{13.6}}{29.92} \times V_m \times \frac{520°R}{T_m \text{ Avg. } °R} = \frac{29.87 + \frac{2.0}{13.6}}{29.92} \times 10.43 \times \frac{520}{546 \; (86+460)} = 9.97$ SCF

Meter Correction: $V_{sc} = V_S \times$ Meter Correction Factor (YD) $= 9.97 \times 1.015 = 10.12$ SCF

****

FLUE GAS MOISTURE:

Imp #1 (gm) ______ - ______ = ______ gm Imp #3 (gm) ______ - ______ = ______ gm

Imp #2 (gm) ______ - ______ = ______ gm Imp #4 (gm) (Silica gel) ______ - ______ = ______ gm

Σgm water = 32 gm

32 gm $H_2O \times 0.0464 \frac{ft^3}{gm} = 1.48$ ft³ H_2O (H_2O Vol.)

$(V_{sc}) + H_2O$ Vol. $= 10.12 + 1.48 = 11.6$ ft³ Total Sample Volume; $\frac{H_2O \text{ Vol.} \times 100\%}{\text{Total Sample Vol.}} = 12.76\%$ H_2O

****

TITRATIONS:

Normality of ~~NaOH~~ Barium Perchlorate solution = .01029 N

Sample Titrated By J. M.

Date Samples Titrated 4/6/83

Date ~~NaOH~~ Standarized 2/7/83.

Probe inlet Plug* & Probe sample - ______ ml

Coil inlet Plug* sample - ______ ml

Coil and Frit sample - ______ ml

Impingers (Sample vol. 435 ml; Aliquot 10 ml) - (1) 22.6 ml, (2) 22.7 ml, (3) 22.6 ml, 22.6 (Avg.)

* If SOx test is conducted on a boiler where a fuel additive is being injected, these plugs shall be kept separate and water extracts taken for chemical analysis of magnesium and sulfate.

****

SO_2

KVB
A Research-Cottrell Company

SOx TEST DATA SHEET

SOx AUDIT

Test No. C Date 4/4/83 Plant/Unit No. FREE BRIMSTONE POWER Unit Load (MW) ____

Sample Location STACK 1 Control Box GN 914 Tests Conducted By PGJ

$Y_D = 1.015$

TEST DATA:

Time	Meter Vol. ft^3	Orifice ΔH " H_2O	Vacuum " H_g	Stack Temp. °F	Probe Temp. °F	~~Oven~~ Coil Temp. °F	Impinger Temp., °F In	Impinger Temp., °F Out	Meter Temp., °F In	Meter Temp., °F Out	Excess O_2 %
START	045.21 (V_I)	1.0	3.8	330	345	149	68	68	75	82	4.1
	047.19	1.0	3.9	330	344	151	69	68	79	84	4.0
20 mins	049.22	1.0	3.9	335	342	150	70	70	82	86	4.0
	051.22	1.0	4.0	335	345	149	70	69	85	90	4.0
	053.30	1.0	4.0	330	350	150	70	70	87	92	4.1
	055.08 (V_F)	1.0	4.0	330	345	151	68	70	89	94	4.2
AVG.	9.87	1.0	3.9	332	345	150	69	69	83	88	4.1

Barometric Pres. 29.87 "Hg Boiler using additive (Type/Rate) ____

* * *

METER VOLUME:

$V_F - V_I = V_m =$ 55.08 − 45.21 = 9.87 ft^3; Sampling Rate $= \frac{V_m}{\text{Length of Test}} =$ .49 ft^3/min.

Temp. & Pres. Correction: $V_S = \frac{B.P. + \frac{\Delta H}{13.6}}{29.92} \times V_m \times \frac{520°R}{T_m \text{ Avg. } °R} = \frac{29.87 + \frac{1.0}{13.6}}{29.92} \times 9.87 \times \frac{520}{546} = 9.41$ SCF

(86+460)

Meter Correction: $V_{sc} = V_S \times$ Meter Correction Factor (YD) = 9.41 × 1.015 = 9.55 SCF

* * *

FLUE GAS MOISTURE:

Imp #1 (gm) ____ − ____ = ____ gm Imp #3 (gm) ____ − ____ = ____ gm

Imp #2 (gm) ____ − ____ = ____ gm Imp #4 (gm) (Silica gel) ____ − ____ = ____ gm

Σgm water = 29.5 gm

29.5 gm $H_2O \times 0.0464 \frac{ft^3}{gm} =$ 1.37 ft^3 H_2O (H_2O Vol.)

(V_{sc}) + H_2O Vol. = 9.55 + 1.37 = 10.92 ft^3 Total Sample Volume; $\frac{H_2O \text{ Vol.} \times 100\%}{\text{Total Sample Vol.}} =$ 12.55 % H_2O

* * *

TITRATIONS:

Probe inlet Plug* & Probe sample − ____ ml

Coil inlet Plug* sample − ____ ml

Coil and Frit sample − ____ ml

Impingers (Sample vol. 365 ml; Aliquot 10 ml) − (1) 12.6 ml, (2) 12.8 ml, (3) 12.6 ml,
12.7 (Avg.)

Normality of ~~NaOH~~ Barium Perchlorate solution = .01029 N

Sample Titrated By J.M.

Date Samples Titrated 4/6/83

Date ~~NaOH~~ Standarized 2-7-83

* If SOx test is conducted on a boiler where a fuel additive is being injected, these plugs shall be kept separate and water extracts taken for chemical analysis of magnesium and sulfate.

* * *

SO2

A Research-Cottrell Company

SOx TEST DATA SHEET

SOx AUDIT

Test No. D Date 4/4/83 Plant/Unit No. FIRE + BRIMSTONE POWER Unit Load (MW) ______

Sample Location STACK 2 Control Box EW 914 Tests Conducted By RDG

$Y_D = 1.015$

TEST DATA:

Time	Meter Vol. ft^3	Orifice ΔH " H_2O	Vacuum " H_g	Stack Temp. °F	Probe Temp. °F	~~Oven~~ Coil Temp. °F	Impinger Temp., °F In	Impinger Temp., °F Out	Meter Temp., °F In	Meter Temp., °F Out	Excess O_2 %
START	071.28 (V_I)	2.1	6.	485	475	149	100	65	82	88	2.9
	073.35	2.0	5.5	480	475	150	100	70	83	89	3.1
20 mins	075.30	2.0	5.5	475	480	150	105	70	86	92	3.0
	077.325	2.0	5.5	485	480	150	107	69	97	93	3.1
	079.41	2.0	5.0	490	485	151	110	70	91	95	2.9
STOP	081.13 (V_F)	2.0	5.0	475	480	149	110	69	93	97	2.8
AVG.	9.85	2.0	5.4	482	479	150	105	68	88	92	3.0

Barometric Pres. 29.87 "Hg Boiler using additive (Type/Rate) ______

* * *

METER VOLUME:

$V_F - V_I = V_m =$ 81.13 − 71.28 = 9.85 ft^3; Sampling Rate = $\frac{V_m}{\text{Length of Test}}$ = .49 ft^3/min.

Temp. & Pres. Correction: $V_S = \frac{B.P. + \frac{\Delta H}{13.6}}{29.92} \times V_m \times \frac{520°R}{T_m \text{ Avg. } °R} = \frac{29.87 + \frac{2.0}{13.6}}{29.92} \times 9.85 \times \frac{520}{550} = 9.34$ SCF

Meter Correction: $V_{sc} = V_S$ x Meter Correction Factor (YD) = 9.34 x 1.015 = 9.48 SCF

* * *

FLUE GAS MOISTURE:

Imp #1 (gm) ______ - ______ = ______ gm Imp #3 (gm) ______ - ______ = ______ gm

Imp #2 (gm) ______ - ______ = ______ gm Imp #4 (gm) (Silica gel) ______ - ______ = ______ gm

Σgm water = 31.0 gm

31 gm H_2O x 0.0464 $\frac{ft^3}{gm}$ = 1.44 ft^3 H_2O (H_2O Vol.)

(V_{sc}) + H_2O Vol. = 9.48 + 1.44 = 10.92 ft^3 Total Sample Volume; $\frac{H_2O \text{ Vol. x } 100\%}{\text{Total Sample Vol.}}$ = 13.19 % H_2O

* * *

TITRATIONS:

Normality of ~~NaOH~~ Barium Perchlorate solution = .01029 N

Sample Titrated By J. M.

Date Samples Titrated 4/6/83

Date ~~NaOH~~ Standarized 2/7/83

Probe inlet Plug* & Probe sample - ______ ml

Coil inlet Plug* sample - ______ ml

Coil and Frit sample - ______ ml

Impingers (Sample vol. 485 ml; Aliquot 10 ml) - (1) 19.9 ml, (2) 19.9 ml, (3) 20.1 ml,
20 (Avg.)

* If SOx test is conducted on a boiler where a fuel additive is being injected, these plugs shall be kept separate and water extracts taken for chemical analysis of magnesium and sulfate.

* * *

KVB®

REPORT OF LAB ANALYSIS

Date: 4/4/83

No. 80 6030 ~~80 3060~~

Client: EPA - IERL

Material: QA AUDIT - KVB INTERNAL

Analysis for: SO_2 - CALCULATIONS AND LAB ANALYSES

RESULTS:

AUDIT SAMPLE I.D.	A	B	C	D
ml 0.1000 N H_2SO_4 Added	46.00	160.2	45.90	99.4

METHOD:

STANDARDIZED H_2SO_4 @ 0.1000 N (± 0.0005) ADDED TO APPROX. 200 ml of DEIONIZED WATER EACH. 50-100 ml D.I. WATER Added to each; SAMPLE CAPPED, MARKED, SHAKE AND DELIVERED TO PROJECT ENGINEER

By Roger D. Griffin

Roger D. Griffin, M.S., P.E.
Manager, Technical Services

SO2

AUDIT MASTER

KVB
A Research-Cottrell Company

SOx TEST DATA SHEET

Test No. SOx Audit A Date 4/4/83 Plant/Unit No. Fire & Brimstone Power Unit Load (MW) ________

Sample Location STACK 1 Control Box Ev 914 Tests Conducted By ________

$Y_D = 1.015$

TEST DATA:

Time	Meter Vol. ft^3	Orifice ΔH " H_2O	Vacuum " H_g	Stack Temp. °F	Probe Temp. °F	~~Oven~~ Coil Temp. °F	Impinger Temp., °F In	Impinger Temp., °F Out	Meter Temp., °F In	Meter Temp., °F Out	Excess O_2 %
START	032.675 (V_I)	1.0	4	325	325	149	100	62	71	81	4
	033.72	1.0	4			148	101	61	73	88	
	035.69	1.1	4	324	340	150	101	61	78	89	4
	037.62	1.0	4			150		-	79	91	4
	039.69	1.0	4	328	340	149	102	68	80	91	4
STOP	042.620 (V_F)	1.0	4	329					81	91	4
AVG.	9.945	1.0							77	89	

83

Barometric Pres. 29.87 "Hg Boiler using additive (Type/Rate) ________

****

METER VOLUME:

$V_F - V_I = V_m =$ ________ $-$ ________ $= 9.945$ ft^3; Sampling Rate $= \frac{V_m}{\text{Length of Test}} =$ ________ ft^3/min.

Temp. & Pres. Correction: $V_S = \frac{B.P. + \frac{\Delta H}{13.6}}{29.92} \times V_m \times \frac{520°R}{T_m \text{ Avg. } °R} = \frac{29.87 + \frac{1}{13.6}}{29.92} \times 9.945 \times \frac{520}{543} = 9.531$ SCF

Meter Correction: $V_{sc} = V_S \times$ Meter Correction Factor (YD) $= 9.531 \times 1.015 = 9.674$ SCF

****

FLUE GAS MOISTURE:

Imp #1 (gm) ________ - ________ = ________ gm Imp #3 (gm) ________ - ________ = ________ gm

Imp #2 (gm) ________ - ________ = ________ gm Imp #4 (gm) (Silica gel) ________ - ________ = ________ gm

Σgm water = 29 gm

29 gm $H_2O \times 0.0464 \frac{ft^3}{gm} = 1.346$ ft^3 H_2O (H_2O Vol.)

$(V_{sc}) + H_2O$ Vol. $= 9.674 + 1.346 = 11.020$ ft^3 Total Sample Volume; $\frac{H_2O \text{ Vol.} \times 100\%}{\text{Total Sample Vol.}} = 12.2$ % H_2O

1.346

****

TITRATIONS:

Probe inlet Plug* & Probe sample - ________ ml

Coil inlet Plug* sample - ________ ml

Coil and Frit sample - ________ ml

Impingers (Sample vol. ____ ml; Aliquot ________ ml) - (1) ________ ml, (2) ________ ml, (3) ________ ml, ________ (Avg.)

Normality of NaOH solution = ________ N

Sample Titrated By ________

Date Samples Titrated ________

Date NaOH Standarized ________

* If SOx test is conducted on a boiler where a fuel additive is being injected, these plugs shall be kept separate and water extracts taken for chemical analysis of magnesium and sulfate.

****

AUDIT MASTER

SAMPLE A

CALCULATIONS:

O_2 CORRECTION: 3% O_2 Correction factor = $\frac{18}{21-\%\ O_2\ (Avg)}$ = $\frac{18}{21-\ 4}$ = 1,0588

****

$[SO_3]$:

____ ml (#1 Plug & Probe)
____ ml (#2 Plug)
____ ml (Coil & Frit)

$\Bigg\}$ x ____ N x $\frac{80}{2}$ x $\frac{\_\_\_\_}{\_\_\_\_\ Vsc}$ x $\frac{836}{80}$ = $\Bigg\{$

____ ppm SO_3 #1 Plug & Probe
____ ppm SO_3 #2 Plug
____ ppm SO_3 #3 Coil & Frit
____ Total ppm SO_3

Total ppm SO_3 @ 3% O_2 = ____ ppm SO_3 x ____ (3% O_2 corr. factor) = ____ ppm SO_3 @ 3% O_2

****

$[SO_2]$:

____ ml (Impinger Avg.) x $\frac{\text{ml Total Sample}}{\_\_\_\ \text{ml Aliquot}}$ x ____ N x $\frac{64}{2}$ x $\frac{1}{\_\_\_\_\ Vsc}$ x $\frac{836}{64}$ = ____ ppm SO_2

Total ppm SO_2 @ 3% O_2 = ____ ppm SO_2 x ____ (3% O_2 corr. factor) = ____ ppm SO_2 @ 3% O_2

****

% Conversion $SO_2 \rightarrow SO_3$ (APH inlet side only):

$\frac{\text{ppm } SO_3 \text{ @ 3\% } O_2}{\text{ppm } SO_3 \text{ @ 3\% } O_2 + \text{ppm } SO_2 \text{ @ 3\% } O_2}$ x 100% = $\frac{\_\_\_\_\_\_}{\_\_\_\_ + \_\_\_\_}$ x 100% = ____ % conversion

KVB3 DS28940-9

TRUE CONCENTRATION

$46.0\ ml \times 0.1000\ N (H_2SO_4) \times 32\ mg\ SO_2/meq = 147.2\ mg\ SO_2$

$C = 147.2 / 9.674 = 15.216\ mg/SDCF$

$\hookrightarrow \times \frac{836}{64} = 198.8\ ppmV\ SO_2$

$\hookrightarrow \times 1.0588 = 210\ ppmV\ @3\%\ O_2$

AUDIT MASTER

[SO2]

KVB
A Research-Cottrell Company

SOx TEST DATA SHEET

Test No. SOx Audit B   Date 4/4/83   Plant/Unit No. Fire & Brimstone Power   Unit Load (MW) ______

Sample Location Stack 2   Control Box EW 9/14 $Y_D = 1.015$ Tests Conducted By RGz

TEST DATA:

Time	Meter Vol. ft^3	Orifice ΔH " H_2O	Vacuum " H_g	Stack Temp. °F	Probe Temp. °F	~~Oven~~ Coil Temp. °F	Impinger Temp., °F In	Impinger Temp., °F Out	Meter Temp., °F In	Meter Temp., °F Out	Excess O_2 %
START	058.82 (V_I)	2.0	5	480	475	149	100	65	75	78	2.9
	060.74	2.0	5	485	480	151	105	70	79	82	2.8
	062.69	2.0	5.2	483	480	150	106	72	82	85	2.9
	064.59	2.1	5.5	485	480	150	106	72	88	89	2.9
	066.70	2.1	5.5	485	485	149	106	75	91	93	2.8
STOP	069.25 (V_F)	2.1	5.5	480	482	150	106	74	95	97	2.9
AVG.	10.43	2.05							85/ 86	87	2.85

Barometric Pres. 29.87 "Hg   Boiler using additive (Type/Rate) ______

****

METER VOLUME:

$V_F - V_I = V_m$ = ______ - ______ = 10.43 ft^3;   Sampling Rate = $\frac{V_m}{\text{Length of Test}}$ = ______ ft^3/min.

Temp. & Pres. Correction: $V_S = \frac{B.P. + \frac{\Delta H}{13.6}}{29.92} \times V_m \times \frac{520°R}{T_m \text{ Avg. } °R} = \frac{29.87 + \frac{2.05}{13.6}}{29.92} \times 10.43 \times \frac{520}{546} = 9.967$ SCF

Meter Correction: $V_{sc} = V_S$ x Meter Correction Factor (YD) = 9.9668 x 1.015 = 10.116 SCF

****

FLUE GAS MOISTURE:

Imp #1 (gm) ______ - ______ = ______ gm   Imp #3 (gm) ______ - ______ = ______ gm

Imp #2 (gm) ______ - ______ = ______ gm   Imp #4 (gm) (Silica gel) ______ - ______ = ______ gm

Σgm water = 32 gm

32 gm H_2O x 0.0464 $\frac{ft^3}{gm}$ = 1.485 ft^3 H_2O (H_2O Vol.)

(V_{sc}) + H_2O Vol. = 10.116 + 1.485 = 11.60 ft^3 Total Sample Volume; $\frac{H_2O \text{ Vol.} \times 100\%}{\text{Total Sample Vol.}}$ (1.485) = 12.8 % H_2O

****

TITRATIONS:

Normality of NaOH solution = ______ N

Sample Titrated By ______

Date Samples Titrated ______

Date NaOH Standarized ______

Probe inlet Plug* & Probe sample - ______ ml

Coil inlet Plug* sample - ______ ml

Coil and Frit sample - ______ ml

Impingers (Sample vol. ____ ml; Aliquot ______ ml) - (1) ______ ml, (2) ______ ml, (3) ______ ml, ____ (Avg.)

* If SOx test is conducted on a boiler where a fuel additive is being injected, these plugs shall be kept separate and water extracts taken for chemical analysis of magnesium and sulfate.

****

AUDIT MASTER

SAMPLE B

CALCULATIONS:

O_2 CORRECTION: 3% O_2 Correction factor $= \frac{18}{21-\%\ O_2\ (\text{Avg})} = \frac{18}{21-\underline{2.85}} = \underline{0.992}$

****

$[SO_3]$:

$$\left.\begin{array}{l} \underline{\qquad\quad}\ \text{ml (\#1 Plug \& Probe)} \\ \underline{\qquad\quad}\ \text{ml (\#2 Plug)} \\ \underline{\qquad\quad}\ \text{ml (Coil \& Frit)} \end{array}\right\} \times \underline{\qquad\quad}\ N \times \frac{80}{2} \times \frac{\underline{\qquad\qquad}}{\underline{\qquad\quad}\ Vsc} \times \frac{836}{80} = \left\{\begin{array}{l} \underline{\qquad\quad}\ \text{ppm } SO_3\ \text{\#1 Plug \& Probe} \\ \underline{\qquad\quad}\ \text{ppm } SO_3\ \text{\#2 Plug} \\ \underline{\qquad\quad}\ \text{ppm } SO_3\ \text{\#3 Coil \& Frit} \\ \underline{\qquad\quad}\ \text{Total ppm } SO_3 \end{array}\right.$$

Total ppm SO_3 @ 3% O_2 = ________ ppm SO_3 × ________ (3% O_2 corr. factor) = ________ ppm SO_3 @ 3% O_2

****

$[SO_2]$:

$$\underline{\qquad\quad}\ \text{ml (Impinger Avg.)} \times \frac{\text{ml Total Sample}}{\underline{\qquad}\ \text{ml Aliquot}} \times \underline{\qquad\quad}\ N \times \frac{64}{2} \times \frac{1}{\underline{\qquad}\ Vsc} \times \frac{836}{64} = \underline{\qquad\quad}\ \text{ppm } SO_2$$

Total ppm SO_2 @ 3% O_2 = ________ ppm SO_2 × ________ (3% O_2 corr. factor) = ________ ppm SO_2 @ 3% O_2

****

% Conversion $SO_2 \rightarrow SO_3$ (APH inlet side only):

$$\frac{\text{ppm } SO_3 @ 3\%\ O_2}{\text{ppm } SO_3 @ 3\%\ O_2 + \text{ppm } SO_2 @ 3\%\ O_2} \times 100\% = \frac{\underline{\qquad\qquad\qquad}}{\underline{\qquad\quad} + \underline{\qquad\quad}} \times 100\% = \underline{\qquad\quad}\ \%\ \text{conversion}$$

KVB3 DS28940-9

TRUE CONCENTRATION

$100.2\,ml \times 0.1000N\ H_2SO_4 \times \frac{32\ mg\ SO_2}{meq} = 320.64\ mg\ SO_2$

$C = 320.64 / 10.116\ SDCF = 31.696\ mg\ SO_2/SDCF$

$\hookrightarrow \times \frac{836}{64} = \underline{414.0\ ppmV\ SO_2}$

$\hookrightarrow \times 0.992 = \underline{411\ ppmV @ 3\%\ O_2}$

AUDIT MASTER

SO2

KVB
A Research-Cottrell Company

SOx TEST DATA SHEET

SOx AUDIT

Test No. C Date 4/4/83 Plant/Unit No. FRED BRIMSTONE POWER Unit Load (MW) ____

Sample Location STACK 1 Control Box SN 914 Tests Conducted By R[illegible]

TEST DATA:

$Y_D = 1.015$

Time	Meter Vol. ft^3	Orifice ΔH " H_2O	Vacuum " H_g	Stack Temp. °F	Probe Temp. °F	Coil Oven Temp. °F	Impinger Temp., °F In	Impinger Temp., °F Out	Meter Temp., °F In	Meter Temp., °F Out	Excess O_2 %
START	045.218 (V_I)	1.0	3.8	330	345	149	68	68	75	82	4.1
	047.19	1.0	3.9	330	344	151	69	68	79	84	4.0
	049.22	1.0	3.9	335	342	150	70	70	82	86	4.0
	051.22	1.0	4.0	335	345	149	70	69	85	90	4.0
	053.30	1.0	4.0	330	350	150	70	70	87	92	4.1
	055.08 (V_F)	1.0	4.0	330	345	151	68	70	89	94	4.2
AVG.	9.87	1.0							83 85	88	4.1

Barometric Pres. 29.87 "Hg Boiler using additive (Type/Rate) ____

****

METER VOLUME:

$V_F - V_I = V_m =$ ____ - ____ = 9.87 ft^3; Sampling Rate = $\frac{V_m}{\text{Length of Test}}$ = ____ ft^3/min.

Temp. & Pres. Correction : $V_S = \frac{B.P. + \frac{\Delta H}{13.6}}{29.92} \times V_m \times \frac{520°R}{T_m \text{ Avg. } °R} = \frac{29.87 + \frac{1}{13.6}}{29.92} \times 9.87 \times \frac{520}{545} = 9.425$ SCF

Meter Correction: $V_{sc} = V_S \times$ Meter Correction Factor (YD) = 9.425 × 1.015 = 9.566 SCF

****

FLUE GAS MOISTURE:

Imp #1 (gm) ____ - ____ = ____ gm Imp #3 (gm) ____ - ____ = ____ gm

Imp #2 (gm) ____ - ____ = ____ gm Imp #4 (gm) (Silica gel) ____ - ____ = ____ gm

Σgm water = 29.5 gm

29.5 gm $H_2O \times 0.0464 \frac{ft^3}{gm}$ = 1.369 ft^3 H_2O (H_2O Vol.)

$(V_{sc}) + H_2O$ Vol. = 9.566 + 1.369 = 10.935 ft^3 Total Sample Volume; $\frac{H_2O \text{ Vol.} \times 100\%}{\text{Total Sample Vol.}}$ = $\frac{1.369}{}$ = 12.5 % H_2O

****

TITRATIONS:

Normality of NaOH solution = ____ N

Sample Titrated By ____

Date Samples Titrated ____

Date NaOH Standarized ____

Probe inlet Plug* & Probe sample - ____ ml

Coil inlet Plug* sample - ____ ml

Coil and Frit sample - ____ ml

Impingers (Sample vol. ____ ml; Aliquot ____ ml) - (1) ____ ml, (2) ____ ml, (3) ____ ml, ____ (Avg.)

* If SOx test is conducted on a boiler where a fuel additive is being injected, these plugs shall be kept separate and water extracts taken for chemical analysis of magnesium and sulfate.

****

AUDIT MASTER

SAMPLE C

CALCULATIONS:

O_2 CORRECTION: 3% O_2 Correction factor $= \frac{18}{21-\%\ O_2\ (Avg)} = \frac{18}{21-\underline{4.1}} = \underline{1.065}$

* * *

[SO_3]:

$\left.\begin{array}{l}\underline{\qquad}\text{ ml (\#1 Plug \& Probe)}\\ \underline{\qquad}\text{ ml (\#2 Plug)}\\ \underline{\qquad}\text{ ml (Coil \& Frit)}\end{array}\right\} \times \underline{\qquad} N \times \frac{80}{2} \times \frac{\underline{\qquad}}{\underline{\qquad} Vsc} \times \frac{836}{80} = \left\{\begin{array}{l}\underline{\qquad}\text{ ppm } SO_3 \text{ \#1 Plug \& Probe}\\ \underline{\qquad}\text{ ppm } SO_3 \text{ \#2 Plug}\\ \underline{\qquad}\text{ ppm } SO_3 \text{ \#3 Coil \& Frit}\end{array}\right.$

________ Total ppm SO_3

Total ppm SO_3 @ 3% O_2 = ________ ppm SO_3 x ________ (3% O_2 corr. factor) = ________ ppm SO_3 @ 3% O_2

* * *

[SO_2]:

________ ml (Impinger Avg.) x $\frac{\text{ml Total Sample}}{\underline{\qquad}\text{ml Aliquot}} \times \underline{\qquad} N \times \frac{64}{2} \times \frac{1}{\underline{\qquad} Vsc} \times \frac{836}{64} = \underline{\qquad}$ ppm SO_2

Total ppm SO_2 @ 3% O_2 = ________ ppm SO_2 x ________ (3% O_2 corr. factor) = ________ ppm SO_2 @ 3% O_2

* * *

% Conversion $SO_2 \rightarrow SO_3$ (APH inlet side only):

$\frac{\text{ppm } SO_3 \text{ @ 3\% } O_2}{\text{ppm } SO_3 \text{ @ 3\% } O_2 + \text{ppm } SO_2 \text{ @ 3\% } O_2} \times 100\% = \frac{\underline{\qquad\qquad}}{\underline{\qquad} + \underline{\qquad}} \times 100\% = \underline{\qquad}$ % conversion

KVB3 DS28940-9

TRUE CONCENTRATION

$45.9\ ml \times 0.1000\ N\text{-}H_2SO_4 \times \frac{32\ mg\ SO_2}{meq} = 146.88\ mg\ SO_2$

$C = \frac{146.88\ mg\ SO_2}{9.566\ SDCF} = 15.354\ mg/SDCF$

$\hookrightarrow \times \frac{836}{64} = 200.6\ ppmV\text{-}SO_2$

$\hookrightarrow \times 1.065 = 214\ ppmV\text{-}SO_2$ @ 3% O_2

AUDIT MASTER

SO2

KVB
A Research-Cottrell Company

SOx TEST DATA SHEET

SOx AUDIT
Test No. D Date 4/4/83 Plant/Unit No. FIRE + BRIMSTONE POWER Unit Load (MW) ______

Sample Location STACK 2 Control Box EJ 9/4 Tests Conducted By RDz

TEST DATA: $Y_D = 1.015$

Time	Meter Vol. ft^3	Orifice ΔH " H_2O	Vacuum " H_g	Stack Temp. °F	Probe Temp. °F	~~Oven~~ Coil Temp. °F	Impinger Temp., °F In	Impinger Temp., °F Out	Meter Temp., °F In	Meter Temp., °F Out	Excess O_2 %
START	071.28 (V_I)	2.1	6	485	475	149	100	65	82	88	2.9
	073.35	2.0	5.5	480	475	150	100	70	83	89	3.1
	075.30	2.0	5.5	475	480	150	105	70	86	92	3.0
	077.325	2.0	5.5	485	480	150	107	69	91	93	3.1
	079.41	2.0	5.0	490	485	151	110	70	91	95	2.9
STOP	081.13 (V_F)	2.0	5.0	475	480	149	110	69	93	97	2.8
AVG.	9.85	2.0							87.5 90	92.5	3.0

Barometric Pres. 29.87 "Hg Boiler using additive (Type/Rate) ______

****

METER VOLUME:

$V_F - V_I = V_m =$ ______ - ______ = 9.85 ft^3; Sampling Rate = $\frac{V_m}{\text{Length of Test}}$ = ______ ft^3/min.

Temp. & Pres. Correction : $V_S = \frac{\text{B.P.} + \frac{\Delta H}{13.6}}{29.92} \times V_m \times \frac{520°R}{T_m \text{ Avg. } °R} = \frac{29.87 + \frac{2}{13.6}}{29.92} \times 9.85 \times \frac{520}{550} = 9.343$ SCF

Meter Correction: $V_{sc} = V_S \times$ Meter Correction Factor (YD) = 9.3429 × 1.015 = 9.483 SCF

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FLUE GAS MOISTURE:

Imp #1 (gm) ______ - ______ = ______ gm Imp #3 (gm) ______ - ______ = ______ gm

Imp #2 (gm) ______ - ______ = ______ gm Imp #4 (gm) (Silica gel) ______ - ______ = ______ gm

Σgm water = 31.0 gm

31 gm $H_2O \times 0.0464 \frac{ft^3}{gm}$ = 1.438 ft^3 H_2O (H_2O Vol.)

(V_{sc}) + H_2O Vol. = 9.483 + 1.438 = 10.92 ft^3 Total Sample Volume; $\frac{H_2O \text{ Vol.} \times 100\%}{\text{Total Sample Vol.}}$ (1.438) = 13.2 % H_2O

****

TITRATIONS:

Probe inlet Plug* & Probe sample - ______ ml
Coil inlet Plug* sample - ______ ml
Coil and Frit sample - ______ ml
Impingers (Sample vol. ____ ml; Aliquot ______ ml) - (1) ______ ml, (2) ______ ml, (3) ______ ml, ____ (Avg.)

Normality of NaOH solution = ______ N
Sample Titrated By ______
Date Samples Titrated ______
Date NaOH Standarized ______

* If SOx test is conducted on a boiler where a fuel additive is being injected, these plugs shall be kept separate and water extracts taken for chemical analysis of magnesium and sulfate.

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